GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

ECONOMIC ANALYSIS OF THE HIBERNIA DEVELOPMENT

PETROLEUM DIRECTORATE

SPECIAL REPORT PD 80-1

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GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

ECONOMIC ANALYSIS OF THE HIBERNIA DISCOVERY AND THE RELATED PROVINCIAL AND FEDERAL POSITIONS

ECONOMICS UNIT

PETROLEUM DIRECTORATE

SEPTEMBER, 1980

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FOREWORD

I take pleasure in making this report on the economics of the Hibernia development available to the public. Since the discovery of oil in potentially commercial quantities on the Hibernia structure late in 1979, there has been intense and widespread interest in the meaning of this discovery in terms of its probable size, development technology, costs, oil supply and social, environmental and economic impacts.

This report briefly reviews the geology of the area and the technology, cost and timing of development. The report then analyzes in more detail the economics of the development under different assumptions regarding size, costs, crude oil price and regulatory regime. In particular, cash flows to the operating company and its rate of return are examined as well as the cash flows to the Provincial and Federal governments. Cash flows to the Province are placed in the context of the Province's disadvantaged financial situation within the Canadian Confederation.

The following conclusions may be drawn from the material presented in this report.

a) Hibernia has the potential of being an extremely positive factor to the economy and to the oil supply of the Province of Newfoundland and to Canada.

b) Hibernia will be developed only if world prices or near world prices are paid for the produced crude. Newfoundland's policy of charging only 90% of world price for crude sold within Canada represents a significant premium to the Canadian consumer.

c) The Newfoundland and Labrador Petroleum Regulations provide the operating company with an adequate return on its investment and provide the Federal Government with a significant share of the Government take from the resource development.

d) Further benefit to the Federal Government is derived from the decrease in equalization payments to the Province as a result of Provincial oil-derived revenues.

3) Various sharing formulas proposed by the Federal Government result in a gross inequality of treatment of this Province's resources in comparison with those of the other Provinces. Moreover, the income provided to the Province in this way is insufficient to change the long term economic and financial outlook in a significant, positive way. In fact, even under the Newfoundland and Labrador Regulations, income from Hibernia will probably be insufficient to bring the people of this Province up to the national average of wealth.

This report was prepared by the Petroleum Directorate under the Executive Director, Mr. Steven M. Millan. The geology was described by Mr. Martin Sheppard and Mr. David Hawkins and the engineering by Mr. Gordon Gosse in conjunction with Energy Projects Newfoundland Ltd. and Cook Offshore Consultants Ltd. The economic work was done by the Economics Unit of the Directorate under Dr. Pedro Van Meurs and included Messers Lorne Spracklin, John Collins, Cyril Sturge and Barry Rodgers. Computer work was done by James Wyse and James Cardwell, Newfoundland and Labrador Computer Services Ltd. Thanks are also due to Judy Ryall, Debbie Downey, Trudy Parsons and Brenda Doyle for typing and Dr. Rex Gibbons for editing.

With the uncertainties inherent in the petroleum business, forecasting must be an ongoing process. This report, therefore, should be regarded as a first step in a regular series of publications on the petroleum resources of the Province. In view of the importance of this subject to the people of Newfoundland and Labrador and to all Canadians, it is our policy that information be made available to the public in an open and timely manner.

Leo Barry

Leo D. Barry
Minister
Petroleum Directorate

PETROLEUM DIRECTORATE, ST. JOHN'S, NEWFOUNDLAND September, 1980

Abstract

This paper analyzes the economics of the Hibernia development in the light of several of the major issues regarding offshore oil and gas development. The main topics discussed include estimated development and operating costs, effects of alternate pricing policies on Hibernia profitability, revenue sharing under the Newfoundland and Labrador Petroleum Regulations versus the Maritime Agreement, and sequencing of offshore developments.

The most important conclusions of the paper may be summarized as follows:

Costs

The costs of developing the Hibernia oil field would be extremely high. Preliminary estimates contained in the cost study prepared for the Government of Newfoundland and Labrador by Energy Projects Newfoundland Limited and Cooke Offshore Consultants Limited place the costs at $2.7, $3.0 and $4.0 billions for each of the 500, 1000 and 1500 million barrels reserves cases, respectively. Although these cost estimates are viewed as being very preliminary and are presently under review by the Petroleum Directorate, they do represent the best cost data available to date.

Effects of Alternate Pricing Policies on Profitability

In view of these high costs, oil prices will have to be adequate to make the project reasonably attractive to the investors. In view of this, it has been the provincial policy for some years that conventional and frontier oil prices should reach at least 90% of international levels. This study concludes that this price level would be marginally sufficient for the development of Hibernia if such a development were to take place during the next seven years. The study concludes that the full cycle rate of return would only be 17% in constant 1980 dollars.

If offshore costs inflate by 12% or more, as expected, a policy aimed at a $4.00 per year price increase could not be maintained for more than a few years if an adequate level of east coast exploration is to be pursued as a policy objective, as we maintain it should. The $4.00 per year policy would not lead to self-sufficiency in oil because frontier exploration and development cost escalation would rapidly make future developments unprofitable.

Revenue Sharing: The Provincial Versus the Federal Proposal

The Maritime Agreement, proposed as an example of Federal/Provincial revenue sharing by Prime Minister Trudeau*, is very unattractive and unacceptable to the province. Assuming that the equalization formula remains the same until 1992, the net benefits to the province under the federal and provincial proposals (after the deduction of the loss in equalization) compared with the normal anticipated borrowing requirements of the province are as follows:

* Source: Commons Debate, 1980.05.01; Reply by the Right Hon. P.E. Trudeau (Prime Minister) to a question by the Hon. James A. McGrath (MP for St. John's East).

Net Revenues to the
province in millions of constant 1980 dollars
(1000 mm bbls)

Year	Maritime Agreement	Newfoundland Regulations	Borrowing Requirements
1985	107.7	12.7	297.5
1986	161.5	105.4	303.0
1987	282.4	182.1	309.0
1988	411.3	1036.1	315.2
1989	415.4	923.3	321.5
1990	349.9	758.3	327.9
1991	293.1	622.7	334.5
1992	237.5	500.8	341.2
TOTAL	2,258.8	4,141.4	2,549.8

It can be seen from the comparison that the average income to the province under the Maritime Agreement would be less than the provincial borrowing requirements.

Only under the application of the Newfoundland and Labrador Petroleum Regulations, and only then for a few years, would revenues from Hibernia be sufficient to significantly strengthen the provincial economy. Revenues, however, should also be compared with the current per capita provincial direct debt of $3,208, which is projected to increase significantly over the next five years. As a result, it is concluded that, on the basis of a 1000 million barrel Hibernia field, full provincial ownership and control, and a price equal to 90 percent of international levels, provincial revenues would still be insufficient to raise Newfoundland to the average level of Canadian wealth. Several oil fields of Hibernia size would be required to achieve this goal.

Sequencing of Offshore Development

The provincial Petroleum Regulations provide for an orderly sequencing of offshore oil field developments. The application of these regulations is crucial to the optimization of the benefits that would accrue from these developments to Newfoundland, the Maritimes and Canada. If several oil fields were developed in sequence, it would result in the expansion of employment-creating expenditures in the province and the Maritimes. Sequencing would also provide sufficient time for the establishment of the necessary infrastructure to obtain the maximum benefits possible. In developing these regulations, it was necessary to consider several factors. The provincial government is very concerned with the effects of uncontrolled development on the province.

Beyond this, the Newfoundland policy of sequencing developments would not only result in early self-sufficiency in Canada (by 1989) but it would also enable this self-sufficiency to be sustained over a longer period than would the federal position of uncontrolled development.

Addendum

Since the finalization of this report, the federal government has indicated its willingness to modify the Maritime Agreement analyzed in this report such that 100% of royalty income would go to the province.

The Petroleum Directorate has, therefore, undertaken an additional analysis of the government revenue sharing comparison presented in Table 5:4:1 in the light of this modified federal position.

The figures resulting from the subsequent analysis are presented in the following table.

Government Revenue Sharing Comparisons
1000 mm bbls. Reserves Case
($ CDN 1980 millions)

	Newfoundland and Labrador Petroleum Regulations		Maritime Agreement	
	% Prov. Take	% Fed. Take	% Prov. Take	% Fed. Take
90% of international price	73.6	26.4	33.0 (25)	67.0 (75)
Can. Esc. @ $4./yr.	71.1	28.9	30.7 (23)	69.3 (77)
Can. Esc. @ $2./yr.	66.3	33.7	28.1 (21)	71.9 (79)

The figures in brackets represent those contained in Table 5:4:1 recognizing a 75/25 split in royalty income.

It is clear that the modified federal position still provides the federal government with a substantial percentage of the total government take. This new proposal does not, therefore, result in a significant improvement to the province's share of government take.

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1. INTRODUCTION

The hopes of Newfoundland and Labrador for a commercial oil discovery took on new dimensions with the discovery of the Hibernia oil field in August, 1979. The sense of urgency regarding the province's degree of readiness also became more pronounced with the Hibernia discovery. The discovery presents the prospect for economic regeneration in a province burdened with the highest unemployment rate, the highest cost of living and the highest provincial debt of any Canadian province.

To date, drilling operations have been conducted on some 70 wells within the Newfoundland and Labrador continental margin. The first well drilled in Newfoundland waters, Pan-Am Imperial's Tors Cove D-52 well on the Grand Banks, was abandoned in 1966; since then, over 65% of the drilling has been conducted in the Grand Banks area (See Figure 1:1).

The Hibernia P-15 discovery by Chevron Standard Ltd. had a total flow rate from zones tested (through a 26/64 inch choke) of 11,165 barrels of oil per day. The API* gravity rating ranged from 29.0° to 36.2°. The well is estimated to have a potential sustained productive capacity in the order of 20,000 barrels per day. One delineation well, Hibernia O-35, has been drilled, tested and classified as a suspended oil well. Hibernia O-35 had a total flow rate, from zones tested through a 32/64 inch choke, of 12,340 barrels of oil per day. The API gravity of the oil ranged from 24° to 31.4°.

A second delineation well, Hibernia B-08, is currently being drilled and there are indications (from well logs) of hydrocarbons in that well. Meanwhile, the wildcat well Ben Nevis I-45, on a separate geologic structure from Hibernia, has been tested. The first test at Ben Nevis I-45 produced oil at a rate of 1596 barrels per day and gas at a rate of 12 million cubic feet per day. The API gravity of the oil is 38.9°. Subsequent tests over other intervals within the I-45 well failed to produce any significant amounts of hydrocarbons and drilling has now been suspended.

This paper analyzes the economic aspects of several of the major policy issues facing the province regarding offshore oil and gas development in light of the Hibernia discovery. The topics to be discussed include fixed versus floating production systems, pipeline versus tanker transportation, timing of development, costs and cashflows, effects of alternate pricing policies on Hibernia profitability, revenue sharing under the provincial and federal proposals, effects of alternate pricing policies on the current equalization entitlement, and sequencing of offshore developments.

The analysis contained in this report is, of necessity, very preliminary. Results from the Hibernia find are largely based on information from one hole, the P-15 discovery well. As a result, reserves calculations and production estimates may have to be changed substantially as new and more detailed information becomes available. The cost estimates used in this report are taken from a preliminary study undertaken for the Government of Newfoundland and Labrador by Energy Projects Newfoundland Limited and Cooke Offshore Consultants Limited. Cost estimates were made without the benefit of any design details or other engineering considerations and, thus, may be subject to major revisions as this information becomes available. Beyond this, the pricing policy likely to be applicable to Hibernia is not yet known to the Petroleum Directorate.

The analysis is carried out using a computerized financial cashflow model developed by the Government of Newfoundland and Labrador over the last several years for purposes of evaluating offshore oil and gas field developments.

* American Petroleum Institute

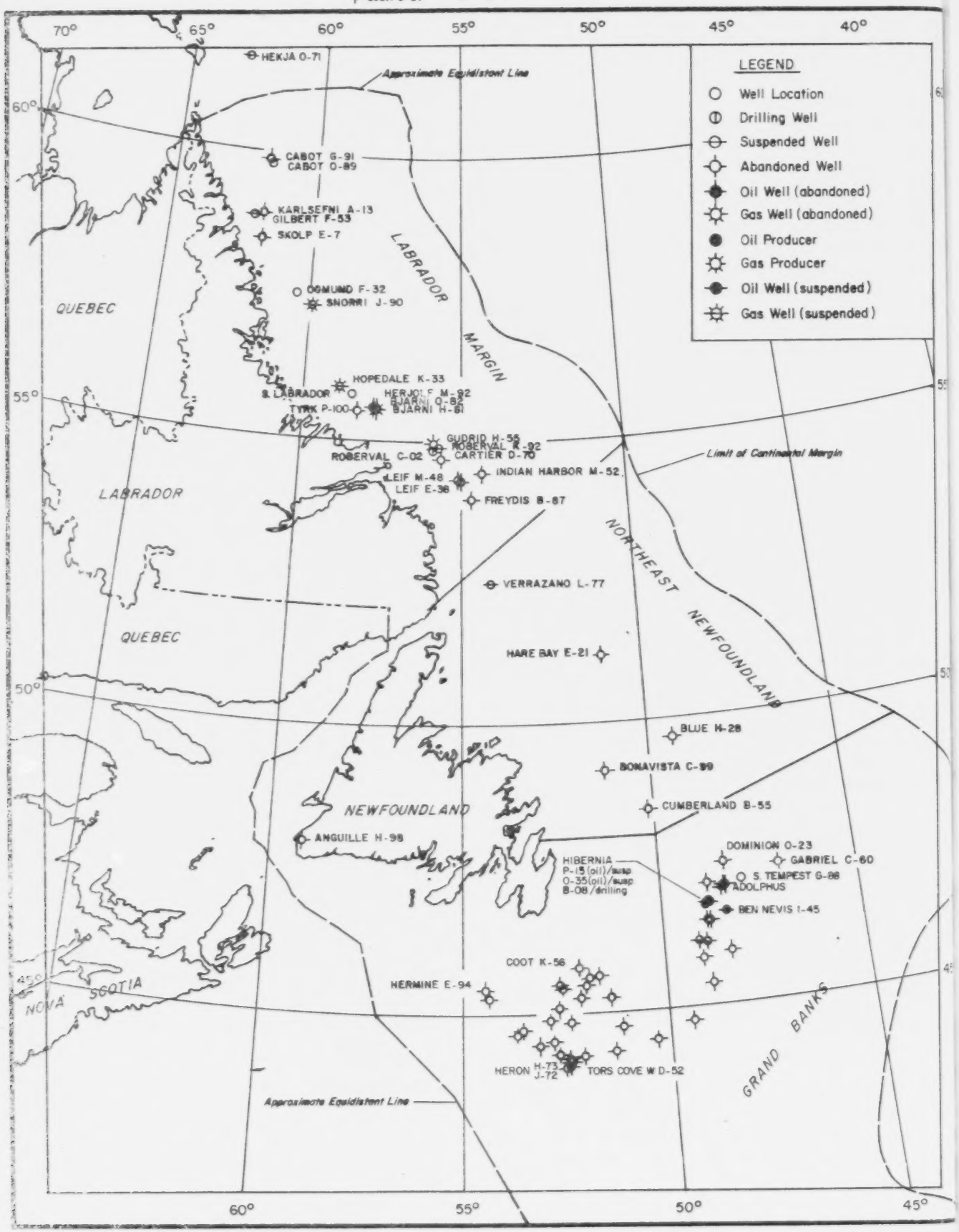


Figure 1;1 Well Location Map

Section 2 contains a general discussion of the Hibernia discovery, including the geology of the area, alternate types of production facilities, alternate modes of transportation, and anticipated timing of developments.

Section 3 presents capital and operating costs and typical cashflows to the operator, assuming the employment of floating production systems. These cost estimates are presented as the base for all subsequent analyses.

Section 4 analyzes the effects of three alternate pricing policies on Hibernia profitability, including the impacts of these pricing policies on cashflow to the operator, on full cycle rate of return, and on subsequent oil field developments.

Section 5 carries the analysis one step further and investigates government revenue sharing under the federal and provincial proposals. Each proposal is analyzed in terms of the three price scenarios assumed for Section 4. The effect on revenues to the province under the current equalization formula is also assessed.

Section 6 discusses the sequencing of offshore developments to illustrate the effect of staging development in accordance with the provincial regulations as opposed to uncontrolled development, which might result from the federal proposal. The sequencing concept is viewed by the Government of Newfoundland and Labrador to be of crucial importance to its overall strategies for facilitating the optimization of benefits and the minimization of environmental, social and economic disruption.

2. THE HIBERNIA DISCOVERY

2.1 Review of the Geology

The discovery well, Chevron et al. Hibernia P-15, located at 46°44'59"N and 48°46'51"W, was spudded on May 27, 1979 by the drillship Glomar Atlantic and suspended on October 21, 1979 at a total depth of 4407 m. The well was reentered on November 10, 1979 with the semi-submersible, Zapata Ugland. Operations at the well were completed on January 7, 1980 and the rig released on the same date.

Hibernia P-15 was the first well drilled within the Province's jurisdiction that flowed potentially commercial amounts of oil. In fact, it was, at the time, the first oil well with commercial possibilities drilled on the Atlantic shelf of North America. With an estimated flow potential of more than 20,000 barrels of oil per day, it has the greatest potential flow rate of any well drilled in Canada to date.

A follow-up well, Mobil et al. Hibernia O-35, was drilled 3.9 km west of the discovery well at 46°44'55"N and 48°49'54"W. That well was spudded on January 1, 1980 by the semisubmersible Sedco 709 and suspended on July 13, 1980, after testing a total of 12,340 barrels of oil per day.

A second step-out well, Mobil et al. Hibernia B-08, is currently being drilled 4.4 km northeast of the discovery well at 46°47'06"N and 48°45'30"W. There are hydrocarbons present in this appraisal well, but to date the well has not been tested.

The Hibernia structure is geologically complex. It is situated on the west side of a trough or depression of thick sedimentary rocks, known geologically as the Jeanne D'Arc sub-basin. To date, oil has been encountered in three principal zones within the structure. Whether these zones of hydrocarbon extend continuously throughout the structure is unknown at the present time. It is evident from the interpretation of seismic data that the three main hydrocarbon-bearing zones are broken and offset by normal faults. Further appraisal drilling is required to determine more precisely the reservoir continuity and, hence, to determine the oil reserves more accurately.

Reliable figures are needed during the early stages of an offshore petroleum field exploration and delineation program for both technical and financial planning purposes. At the time of this review study, most of the information available is from two wells, Hibernia P-15 and O-35. For reasons outlined above, more delineation drilling will have to be done and more data obtained about the structure before more accurate oil reserve calculations can be made.

For purposes of early technical and financial planning, however, three reserve cases have been defined, based on the limited information available to the Petroleum Directorate. The reserve cases examined range from a low of 500 million barrels to a high of 1500 million barrels, with a median case of 1,000 million barrels. These three reserve cases are used for the analysis presented in the remainder of this paper.

2.2 Fixed Versus Floating Systems

The Petroleum Directorate commissioned Energy Projects Newfoundland Limited and Cooke Offshore Consultants Limited to study conventional and innovative production system concepts to provide an overview of the system choices that may be applicable to Hibernia. These systems include: (1) construction of a permanent island; (2) construction of a tunnel from shore combined with caverns as working environments; (3) floating systems; (4) gravity platforms; (5) steel platforms; (6) submerged production systems; and

(7) gravity-positioned icebergs. A number of these concepts are technologically unproven and are, therefore, not considered worthy of further investigation at this time. Two alternative concepts, the gravity platform (Figure 2:2:1) and the floating system (Figure 2:2:2), appear to be feasible for Hibernia. In both cases, a number of areas require further study. For the gravity platform, these studies include interaction between the structure and icebergs, iceberg scour, feasibility of constructing a rock berm, the competence of the seabottom to support the platform, and safety and environmental matters. For the floating system, the studies include ice management procedures and equipment, safety and environmental matters, safe and practical methods for quick release of the floating platform and semi-submersibles, iceberg scour, and operating downtime.

2.2.1 Gravity Platform

The concrete gravity platform would be more than twice the size and weight of the largest gravity platform built to date in the world. The weight, when ballasted, would be in the order of 2 million metric tons. By virtue of its large mass, it would be capable of resisting very large external forces such as icebergs and pack ice. As a safety factor, a rock-filled berm could be constructed around the platform to an elevation of 60 metres above the seafloor, permitting only icebergs with a draft of approximately 20 metres or less to enter the immediate platform area. If a collision occurred, icebergs with a draft of 20 metres would exert considerably less force than that which a 2 million metric ton structure could safely withstand. This type of platform might also serve as a central gathering point for crude and gas from other types of facilities in the field. It could also serve as the junction for main pipeline pumping or tanker loading.

A minimum of 4 years would be required to design and construct such a platform. The platform could be built in the province. In this regard, site selection, availabiliity of required infrastructure, labour skills and sources, and labour stability are all important factors that would require careful consideration and planning. Total labour and supervisory manpower for each platform could be in the order of 1,500 - 2,500 workers (peak) directly involved in the construction phase. Existing civil engineering technology is available to construct this type of platform and construction methods as well as structural design have been well advanced over the last 7 or 8 years. Both marine engineering and naval architecture are sufficiently advanced to ensure that concrete gravity-type platforms can be safely towed to location and installed in a relatively short period of time.

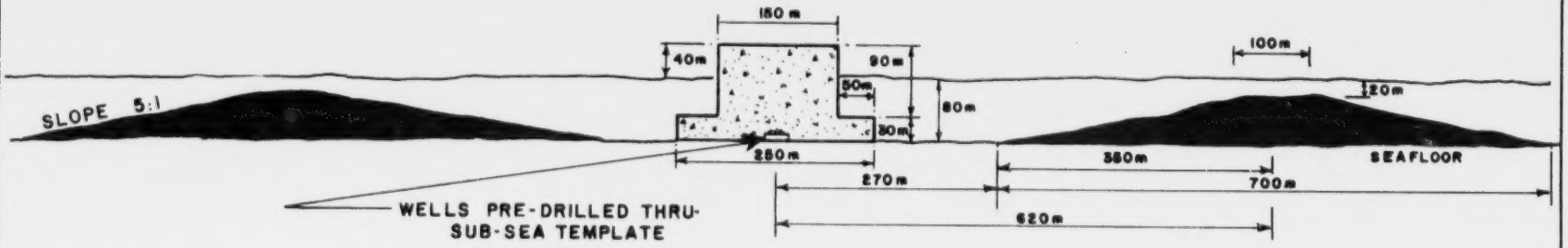
2.2.2 Floating System

The floating system permits the avoidance of impact with pack ice and icebergs. Production would cease and the platform would move off location using quick release systems. The equipment on the seafloor would be located below the expected iceberg scour depth. This concept envisages the use of subsea templates, manifold centers, flowlines, risers, floating production process and oil storage tankers, and conventional semisubmersible drilling units.

Very preliminary cashflow analysis indicates that, for each of the three reserves categories assumed, the floating facility is likely to yield a higher internal rate of return than the gravity platform. On the basis of internal rate of return, the floating system has been chosen for the detailed cashflow analysis presented in this report. This does not imply, however, that the floating system is the most preferred. The choice will be made on the basis of a combination of complex factors including system safety and reliability, pollution risk, social and economic impact, local employment and economic benefits as well as critical engineering factors affecting feasibility.

FIG: 2:2:1 PERMANENT PRODUCTION DESIGN CONCEPT

CONCRETE GRAVITY PLATFORM
WITH EXTERNAL
PROTECTIVE BERM



BERM FILL VOLUME 105 MILLION M^3
BERM LENGTH APPROX. 4000 METERS

NOTES:

1. VERTICAL DIMENSION OF PLATFORM COULD BE REDUCED, AND PLATFORM PLACED ON TOP OF BERM FOUNDATION.
2. OUTWARD SLOPING EXTERIOR WALLS MAY ALSO BE CONSIDERED.
3. PILED MOORING SYSTEM MAY HAVE TO BE USED FOR SEMI-SUB WHILE DRILLING DEVELOPMENT WELLS OR BERMS LOCATED AT GREATER RADIAL DISTANCE FROM PLATFORM CENTERLINE

SOURCE: OVERVIEW STUDY - HIBERNIA FIELD DEVELOPMENT BY ENERGY PROJECTS NEWFOUNDLAND LIMITED AND COOK OFFSHORE CONSULTANTS LIMITED, APRIL, 1980.

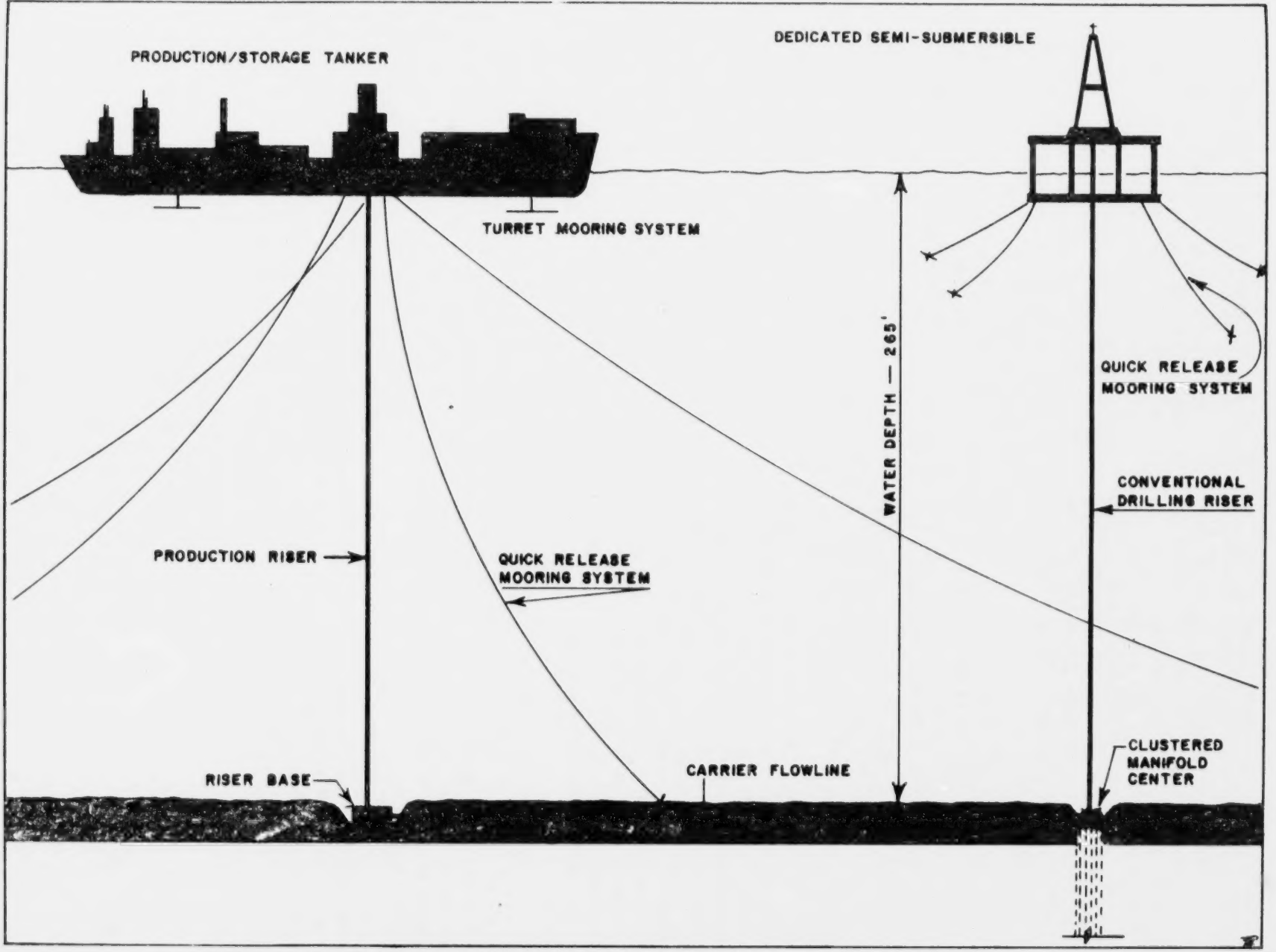


FIG: 2:2:2 FLOATING / SUB-SEA DESIGN CONCEPTS

SOURCE: OVERVIEW STUDY – HIBERNIA FIELD DEVELOPMENT BY ENERGY PROJECTS NEWFOUNDLAND LIMITED AND COOK OFFSHORE CONSULTANTS LIMITED. APRIL. 1980.

2.3 Pipeline Versus Tankers

The analysis contained in this paper assumes a F.O.B. price for Hibernia crude at the production facilities. In other words, costs for transporting the crude are not reflected either in the capital cost or operating cost but rather in the price. As such, it is borne by the purchaser rather than the producer.

The type of transportation system put in place is an important aspect of the overall development. Selection of a transportation system is a complex process of weighing trade-offs among system safety, environmental considerations, capital costs, operating costs, reserves, flow rates, etc.

Under the pipeline system, oil would be transported by offshore pipeline to landfall for transportation via onshore to Come-By-Chance. Refinery products would be distributed for Newfoundland consumption or transported to markets in eastern Canada or the United States. Crude excess to Newfoundland processing needs would be transported from the onshore terminal by tanker to central and eastern Canadian markets.

Under the tanker system, oil required for Newfoundland consumption or refining would be transported by tanker around the Avalon Peninsula to the Come-by-Chance refinery. Excess crude would be transported directly to other Canadian markets.

It should be noted that the transportation configurations discussed here serve illustrative purposes only. Further evaluations are required before a final selection can be made.

2.4 Anticipated Timing of Development

The timing of development, assuming commercially recoverable reserves, will depend upon the resolution of a number of important factors. At least five significant items need to be completed before development can proceed:

1. Commercial reserves must be established.

2. Technical studies analyzing development and transportation alternatives must be completed.

3. Environmental, social and economic impacts of the proposed development must be analyzed.

4. The dispute between the federal and provincial governments over ownership of, and jurisdiction over, offshore mineral resources must be resolved.

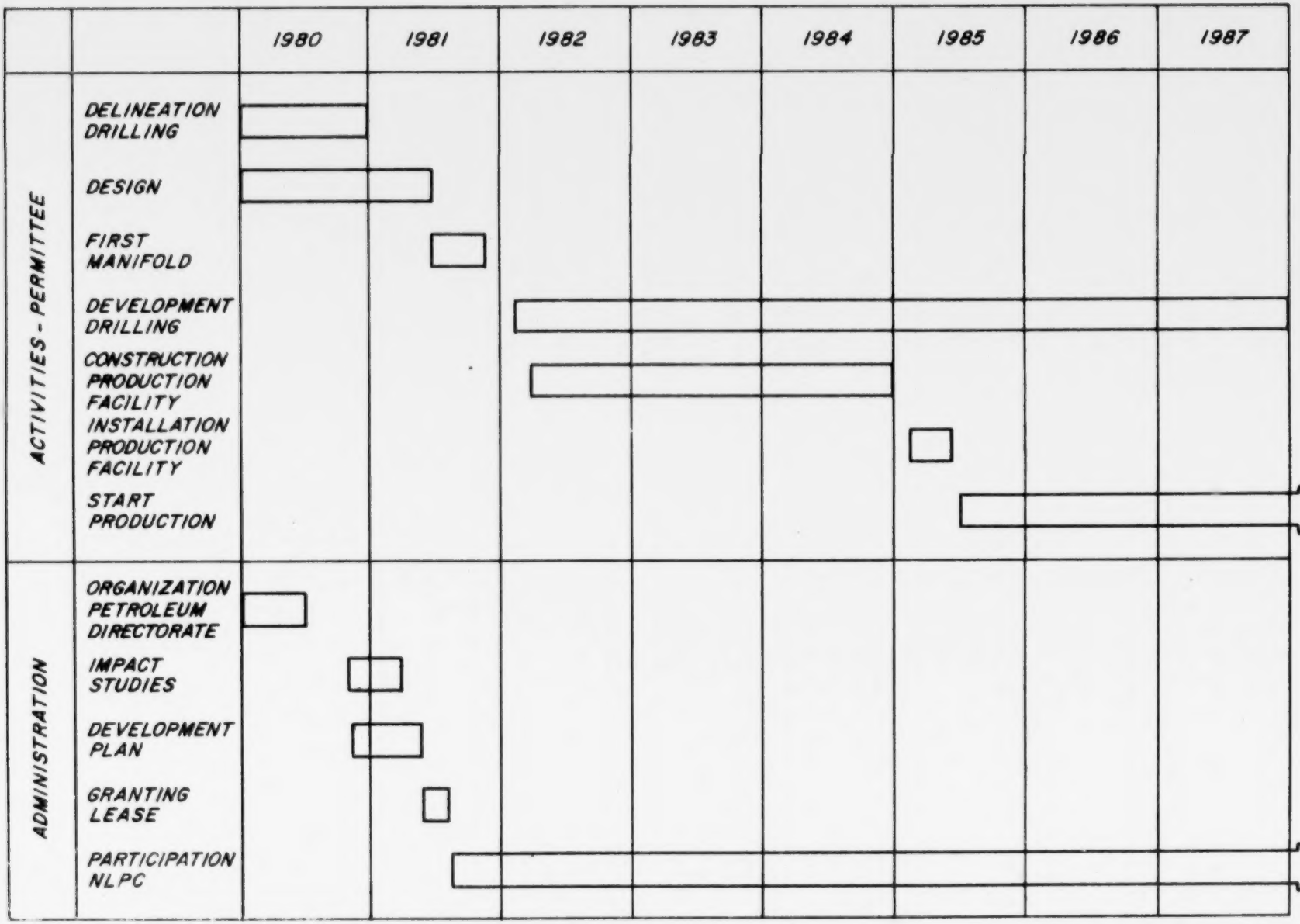
5. The overall development plan must be evaluated and approved by the province, and all necessary authorizations must be acquired from the federal and provincial governments.

6. A pricing policy that would place the development on a sound economic base must be agreed upon.

Figure 2:4:1 gives a development schedule for broadly defined activities on the assumption that all of the above mentioned activities are resolved favorably in the timeframe anticipated.

FIGURE 2.4.1

DEVELOPMENT SCHEDULE FOR THE FLOATING SYSTEM



3. COSTS AND CASHFLOWS FOR A FLOATING SYSTEM

3.1 Capital Cost Estimates

The production scheme assumed for purposes of the following analyses is the floating system.

The capital costs are influenced by environmental and technical considerations, as well as the particular characteristics of the reservoir.

The reservoir characteristics determine such things as the number of platforms and the number and depths of the wells. As stated previously, the characteristics assumed here are based on data from the P-15 discovery well only. Normally, 4-5 delineation wells are required before enough information is available on which to select a final development proposal. Since the production configuration presented here is based on limited information, the associated costs are subject to change as additional data become available.

The cost estimates are presented in Table 3:1:1 and were calculated on the basis of information for similar projects in other offshore areas, particularly the North Sea, by Energy Projects Newfoundland Limited and Cooke Offshore Consultants Limited and are presently under review by the Petroleum Directorate. More accurate and definitive cost estimates will be possible as reservoir information and operating strategies become more firm.

Table 3:1:2 gives a summary by project item of the capital costs for each of the three reserves cases considered in this study. All costs are presented in constant 1980 Canadian dollars. The costs for exploration and delineation wells are not included. Present estimates place these costs at approximately $134 million and are the same for all three reserves cases.

The total capital cost is estimated to be $2.1 billion for the 500 million barrels reserves case, $2.3 billion for the 1,000 million barrels reserves case, and $3.1 billion for the 1,500 million barrels reserves case. A 30% contingency factor has been added to each of the totals bringing them to $2.8 billion, $3.0 billion, and $4.1 billion, respectively.

3.2 Capital Expenditure Phasing

The capital expenditure phasing is based on the assumed project approval and major financial commitment date of January, 1982, and on the overall development schedule presented in Figure 2:4:1.

Tables 3:2:1, 3:2:2, and 3:2:3 provide estimate phasing of capital expenditures for each of the three reserves cases under review. The categories and totals are the same as those presented in Table 3:1:2.

The capital expenditure phasing assumes a 7-year development period beyond 1980 for all three reserves cases. Most of the expenditure is made in the second and third years of the development period.

3.3 Operating Cost Estimates

Table 3:3:1 presents estimates of operating cost for all three reserves cases. The largest items in all cases are transportation of men and equipment, semisubmersibles, and support vessels. General administration and overhead are estimated at about $5 to $7 million. Insurance is estimated at approximately 10% of relevant capital costs.

All costs are in terms of constant 1980 Canadian dollars. The operating cost represents the operating cost of the first full year of production.

Operating cost estimating is very difficult because there is no floating system on this scale in operation

Table 3:1:1

Capital and Operating Costs for a Floating Production System
($ CDN 1980 millions)

	500 mm bbls. case	1000 mm bbls. case	1500 mm bbls. case
Capital Costs	$2,761	$3,028	$4,060
Operating Costs	$199.4/yr	$213.2/yr	$282.7/yr

Source: Overview Study - Hibernia Field Development by Energy Projects Newfoundland Limited and Cook Offshore Consultants Limited, April, 1980.

Table 3:1:2

Estimated Capital Costs by item for the Hibernia Field Development using the Floating System
($ CDN 1980 Millions)

	Project Items	Reserves 500 mm bbls.	1000 mm bbls.	1500 mm bbls.
1)	Preliminary Studies	8.0	8.0	10.0
2)	Templates/CMC's	281.0	281.0	400.0
3)	Riser Base/Riser	40.0	40.0	50.0
4)	Flowlines	12.0	12.0	15.0
5)	Tankers Process/Storage	420.0	420.0	530.0
6)	Topside Facilities	165.0	330.0	490.0
7)	Excavations	320.0	320.0	400.0
8)	Offshore Installation	198.0	198.0	210.0
9)	Bases/Depots	20.0	20.0	25.0
10)	Telecomm/Telemetry	25.0	25.0	30.0
11)	Insurance (2,3,4,5,6)	18.0	22.0	30.0
12)	Admin/Engineering (1-7)	173.0	193.0	253.0
13)	Development Drilling	444.0	460.0	680.0
	Subtotal Base Cost	2,124.0	2,329.0	3,123.0
	Contingency 30%	637.0	699.0	937.0
	Total Base Cost	2,761.0	3,028.0	4,060.0

Source: Overview Study - Hibernia Field Development by Energy Projects Newfoundland Limited and Cook Offshore Consultants Limited, April, 1980.

Table 3:2:1

Capital Expenditure Phasing
Hibernia 500 mm bbls Case
Floating System
($ CDN 1980 Millions)

PROJECT ITEM	TOTAL	1980	1981	1982	1983	1984	1985	1986	1987
1) Preliminary Studies	8	3	5	-	-	-	-	-	-
2) Templates/CMC	281	-	28	120	133	-	-	-	-
3) Riser Base/Riser	40	-	2	15	23	-	-	-	-
4) Flowlines	12	-	-	5	7	-	-	-	-
5) Tankers	420	-	5	200	215	-	-	-	-
6) Topside Facilities	165	-	10	65	65	25	-	-	-
7) Excavations	320	-	10	155	155	-	-	-	-
8) Offshore Installation	198	-	-	8	80	80	30	-	-
9) Bases/Depots	20	-	-	4	4	4	4	4	-
10) Telecomm/Telemetry	25	-	-	10	10	5	-	-	-
11) Insurance (2,3,4,5,6)	18	-	1	8	8	1	-	-	-
12) Admin/Engineering (1-8)	173	1	7	68	81	13	3	-	-
13) Development Drilling	444	-	20	40	57	115	115	57	40
Subtotal	2,124	4	88	698	838	243	152	61	40
Contingency	637	1	26	209	251	73	44	18	15
Total Base Cost	$2,761	5	114	907	1,089	316	196	79	55

Source: Overview Study - Hibernia Field Development by Energy Projects Newfoundland Limited and Cook Offshore Consultants Limited, April, 1980.

Table 3:2:2

Capital Expenditure Phasing
Hibernia 1000 mm bbls Case
Floating System
($ CDN 1980 Millions)

PROJECT ITEM	TOTAL	1980	1981	1982	1983	1984	1985	1986	1987
1) Preliminary Studies	8	3	5	-	-	-	-	-	-
2) Templates/CMC	281	-	28	120	133	-	-	-	-
3) Riser Base/Riser	40	-	2	15	23	-	-	-	-
4) Flowlines	12	-	-	5	7	-	-	-	-
5) Tankers	420	-	5	200	215	-	-	-	-
6) Topside Facilities	330	-	10	135	135	50	-	-	-
7) Excavations	320	-	10	155	155	-	-	-	-
8) Offshore Installation	198	-	-	8	80	80	30	-	-
9) Bases/Depots	20	-	-	4	4	4	4	4	-
10) Telecomm/Telemetry	25	-	-	10	10	5	-	-	-
11) Insurance (2,3,4,5,6)	22	-	1	10	11	-	-	-	-
12) Admin/Engineering (1-8)	193	1	7	76	90	16	3	-	-
13) Development Drilling	460	-	20	40	57	115	115	57	56
Subtotal	2,329	4	88	778	920	270	152	61	56
Contingency	699	1	26	233	276	81	44	18	20
Total Base Cost	$3,028	5	114	1,011	1,196	351	196	79	76

Source: Overview Study - Hibernia Field Development by Energy Projects Newfoundland Limited and Cook Offshore Consultants Limited, April, 1980.

Table 3:2:3

Capital Expenditure Phasing
Hibernia 1500 mm bbls Case
Floating System
($ CDN 1980 Millions)

PROJECT ITEM	TOTAL	1980	1981	1982	1983	1984	1985	1986	1987
1) Preliminary Studies	10	3	7	-	-	-	-	-	-
2) Templates/CMC	400	-	40	150	210	-	-	-	-
3) Riser Base/Riser	50	-	4	20	26	-	-	-	-
4) Flowlines	15	-	-	6	9	-	-	-	-
5) Tankers	530	-	7	250	273	-	-	-	-
6) Topside Facilities	490	-	12	209	209	60	-	-	-
7) Excavations	400	-	15	190	195	-	-	-	-
8) Offshore Installation	210	-	-	9	80	80	42	-	-
9) Bases/Depots	25	-	-	5	5	5	5	5	-
10) Telecomm/Telemetry	30	-	-	10	10	10	-	-	-
11) Insurance (2,3,4,5,6)	30	-	1	13	14	2	-	-	-
12) Admin/Engineering (1-8)	253	1	10	100	120	17	5	-	-
13) Development Drilling	680	-	20	45	84	167	170	97	97
Subtotal	3,123	4	116	1,006	1,235	341	222	102	97
Contingency	937	1	34	302	370	102	67	31	30
Total Base Cost	$4,060	5	150	1,308	1,605	443	289	133	127

Source: Overview Study - Hibernia Field Development by Energy Projects Newfoundland Limited and Cook Offshore Consultants Limited, April, 1980.

Table 3:3:1

Estimated Annual Operating Costs by item for the Hibernia Field Development Using the Floating System ($ CDN 1980 Millions)

	Project Items	Reserves 500 bbls. mm	1000 bbls. mm	1500 bbls. mm
1)	Company Labour	10.0	10.0	13.0
2)	Contract Labour	3.0	3.0	4.0
3)	Contract Services	8.0	11.5	15.0
4)	Diving Support Vessel	23.7	23.7	23.7
5)	Semisubmersibles	44.0	44.0	66.0
6)	Tanker Operations	9.0	9.0	13.5
7)	Fuel	15.0	20.0	25.0
8)	Utilities	2.5	2.5	3.5
9)	Materials/Repair Parts	4.0	6.0	9.0
10)	Transportation (Marine & Air)	22.0	22.0	28.0
11)	Major Expense Jobs	12.0	12.0	15.0
12)	Remedial/Redrill	10.0	10.0	15.0
13)	Ice Management Vessels	8.0	8.0	10.0
14)	General Admin/Overhead	5.0	5.0	7.0
	Subtotal	176.2	186.7	247.7
	Insurance	23.2	26.5	35.0
	Total Cost/Year	$ 199.4	$ 213.2	$ 282.7

Source: Overview Study - Hibernia Field Development by Energy Projects Newfoundland Limited and Cook Offshore Consultants Limited, April, 1980.

anywhere in the world at present. Marine operating costs provide for a diving vessel for year round operation, semisubmersibles for well maintenance, recompletions and workovers, and an allowance for operation of the process and storage tankers. Three ice management and towing vessels have also been included.

3.4 Typical Cashflows

Tables 3:4:1, 3:4:3, and 3:4:5 present typical cashflows to the operator for each of the three reserves cases. The cashflows have been developed based on the capital and operating costs presented earlier adjusted for an anticipated inflation rate of 8% in the case of operating costs and an anticipated combined inflation and escalation rate of 12% in the case of capital costs. The net cashflow is based on the Newfoundland and Labrador Petroleum Regulations and the payment of normal corporate income tax. The price is assumed to be international price inflated annually with the same inflation rate, i.e., 8%, as operating costs. Beyond this, 100% equity financing is assumed, i.e., operating costs do not include interest payments to financial institutions on borrowed capital.

Tables 3:4:2, 3:4:4, and 3:4:6 present the same cashflows discounted at 8%. The cashflows presented in these tables are, therefore, in terms of constant 1980 dollars.

The 12% combined inflation and escalation rate applied to capital costs is probably low and may very well prove to be higher in the final outcome. This is suggested by North Sea experience, in particular, during the period 1971 to 1975 (the latest years for which cost escalation studies have been published) when structure costs in the Norwegian and United Kingdom sectors escalated rather dramatically in a number of years (See Table 3:4:7.).

TABLE 3:4:1
TYPICAL CASHFLOW TO OPERATOR
HIBERNIA OIL 500 MM BBLS
($ CDN CURRENT MILLIONS)

YEAR	PRODUCTION (mm bbls)	INVESTMENT	OPER. COST	REVENUE	NET CASHFLOW	CUMULATIVE CASHFLOW
1980	0.0	134.0	0.0	0.0	-58.7	-58.7
1981	0.0	127.6	0.0	0.0	-112.6	-171.2
1982	0.0	1137.9	0.0	0.0	-996.7	-1167.9
1983	0.0	1530.1	0.0	0.0	-1255.6	-2423.5
1984	0.0	497.4	0.0	0.0	-248.2	-2671.7
1985	30.7	345.4	292.9	1578.9	504.7	-2167.0
1986	42.7	155.5	316.4	2372.0	1044.2	-1122.7
1987	51.8	121.1	341.7	3107.0	1407.0	284.2
1988	54.3	0.0	369.1	3517.6	1684.3	1968.5
1989	48.9	0.0	398.6	3421.5	1588.8	3557.3
1990	41.2	0.0	430.4	3113.1	834.1	4391.4
1991	35.4	0.0	464.9	2889.0	743.7	5135.1
1992	29.9	0.0	502.1	2635.4	645.5	5780.7
1993	27.7	0.0	542.3	2636.8	627.2	6407.8
1994	25.5	0.0	585.7	2621.4	603.5	7011.3
1995	24.4	0.0	632.5	2709.1	611.3	7622.6
1996	21.8	0.0	683.1	2614.0	561.7	8184.3
1997	19.7	0.0	737.8	2551.1	521.0	8705.3
1998	17.5	0.0	796.8	2447.5	466.4	9171.7
1999	14.9	0.0	860.5	2250.6	381.5	9553.2
2000	13.6	0.0	929.4	2218.6	345.6	9898.8
2001	0.0	0.0	0.0	0.0	0.5	9899.3
2002	0.0	0.0	0.0	0.0	0.2	9899.5
2003	0.0	0.0	0.0	0.0	0.1	9899.7
TOTAL	500.0	4049.0	8884.2	2683.6	9899.7	

TABLE 3:4:2
TYPICAL CASHFLOW TO OPERATOR
HIBERNIA OIL 500 MM BBLS
($ CDN 1980 MILLIONS)

YEAR	PRODUCTION (mm bbls)	INVESTMENT	OPER. COST	REVENUE	NET CASHFLOW	CUMULATIVE CASHFLOW
1980	0.0	134.0	0.0	0.0	-58.7	-58.7
1981	0.0	118.1	0.0	0.0	-104.2	-162.9
1982	0.0	975.5	0.0	0.0	-854.5	-1017.4
1983	0.0	1214.6	0.0	0.0	-996.7	-2014.1
1984	0.0	365.6	0.0	0.0	-182.5	-2196.5
1985	30.7	235.1	199.3	1074.6	343.5	-1853.0
1986	42.7	98.0	199.4	1494.8	658.0	-1195.0
1987	51.8	70.7	199.4	1812.9	821.0	-374.0
1988	54.3	0.0	199.4	1900.4	910.0	535.9
1989	48.9	0.0	199.4	1711.6	794.8	1330.7
1990	41.2	0.0	199.4	1442.0	386.4	1717.1
1991	35.4	0.0	199.4	1239.0	319.0	2036.0
1992	29.9	0.0	199.4	1046.6	256.4	2292.4
1993	27.7	0.0	199.4	969.5	230.6	2523.0
1994	25.5	0.0	199.4	892.5	205.5	2728.5
1995	24.4	0.0	199.4	854.0	192.7	2921.2
1996	21.8	0.0	199.4	763.0	164.0	3085.1
1997	19.7	0.0	199.4	689.5	140.8	3226.0
1998	17.5	0.0	199.4	612.5	116.7	3342.7
1999	14.9	0.0	199.4	521.5	88.4	3431.1
2000	13.6	0.0	199.4	476.0	74.1	3505.2
2001	0.0	0.0	0.0	0.0	0.1	3505.3
2002	0.0	0.0	0.0	0.0	0.0	3505.4
TOTAL	500.0	211.7	3190.3	17500.4	3505.4	

TABLE 3:4:3
TYPICAL CASHFLOW TO OPERATOR
HIBERNIA OIL 1000 MM BBLS
($ CDN CURRENT MILLIONS)

YEAR	PRODUCTION (mm bbls)	INVESTMENT	OPER. COST	REVENUE	NET CASHFLOW	CUMULATIVE CASHFLOW
1980	0.0	134.0	0.0	0.0	-58.7	-58.7
1981	0.0	127.6	0.0	0.0	-112.6	-171.2
1982	0.0	1267.9	0.0	0.0	-1111.8	-1283.0
1983	0.0	1680.7	0.0	0.0	-1378.4	-2661.5
1984	0.0	552.8	0.0	0.0	-277.8	-2939.3
1985	61.3	345.4	313.3	3152.7	1311.0	-1628.4
1986	85.4	155.5	338.3	4744.0	2189.2	560.8
1987	104.0	167.8	365.4	6237.9	2836.1	3396.9
1988	109.5	0.0	394.6	7093.4	2013.4	5410.3
1989	98.6	0.0	426.2	6899.0	1937.6	7347.9
1990	83.6	0.0	460.3	6316.8	1758.2	9106.1
1991	71.2	0.0	497.1	5810.6	1603.8	10709.8
1992	60.2	0.0	536.9	5306.0	1452.2	12162.0
1993	51.5	0.0	579.8	4902.3	1317.7	13479.7
1994	43.8	0.0	626.2	4502.6	1173.3	14653.0
1995	40.2	0.0	676.3	4463.4	1140.3	15793.3
1996	37.2	0.0	731.4	4460.6	1117.5	16910.8
1997	31.0	0.0	788.8	4014.5	956.7	17867.5
1998	27.7	0.0	851.9	3874.1	889.1	18756.6
1999	27.6	0.0	920.1	4169.0	955.1	19711.7
2000	24.8	0.0	993.7	4045.6	889.2	20600.9
2001	22.3	0.0	1073.2	3928.8	823.0	21423.9
2002	20.1	0.0	1159.1	3824.6	758.3	22182.3
2003	0.0	0.0	0.0	0.0	0.2	22182.4
TOTAL	1000.0	4431.7	11732.6	87745.9	22182.4	

TABLE 3:4:4
TYPICAL CASHFLOW TO OPERATOR
HIBERNIA OIL 1000 MM BBLS
($ CDN 1980 MILLIONS)

YEAR	PRODUCTION (mm bbls)	INVESTMENT	OPER. COST	REVENUE	NET CASHFLOW	CUMULATIVE CASHFLOW
1980	0.0	134.0	0.0	0.0	-58.7	-58.7
1981	0.0	118.1	0.0	0.0	-104.2	-162.9
1982	0.0	1087.1	0.0	0.0	-953.2	-1116.1
1983	0.0	1334.2	0.0	0.0	-1094.3	-2210.3
1984	0.0	406.3	0.0	0.0	-204.2	-2414.6
1985	61.3	235.1	213.2	2145.7	892.2	-1522.4
1986	85.4	98.0	213.2	2989.5	1379.5	-142.8
1987	104.0	97.9	213.2	3639.8	1654.9	1512.0
1988	109.5	0.0	213.2	3832.4	1087.8	2599.8
1989	98.6	0.0	213.2	3451.3	969.3	3569.1
1990	83.6	0.0	213.2	2925.9	814.4	4383.5
1991	71.2	0.0	213.2	2492.1	687.8	5071.3
1992	60.2	0.0	213.2	2107.1	576.7	5648.0
1993	51.5	0.0	213.2	1802.6	484.5	6132.5
1994	43.8	0.0	213.2	1533.0	399.5	6532.0
1995	40.2	0.0	213.2	1407.1	359.5	6891.5
1996	37.2	0.0	213.5	1302.0	326.2	7217.7
1997	31.0	0.0	213.2	1085.0	258.6	7476.2
1998	27.7	0.0	213.2	969.5	222.5	7698.7
1999	27.6	0.0	213.2	966.0	221.3	7920.0
2000	24.8	0.0	213.2	868.0	190.8	8110.8
2001	22.3	0.0	213.2	780.5	163.5	8274.3
2002	20.1	0.0	213.2	703.5	139.5	8413.8
TOTAL	1000.0	3510.7	3837.9	35000.8	8413.8	

TABLE 3:4:5
TYPICAL CASHFLOW TO OPERATOR
HIBERNIA OIL 150 MM BBLS
($ CDN CURRENT MILLIONS)

YEAR	PRODUCTION (mm bbls)	INVESTMENT	OPER. COST	REVENUE	NET CASHFLOW	CUMULATIVE CASHFLOW
1980	0.0	134.0	0.0	0.0	-58.7	-58.7
1981	0.0	168.0	0.0	0.0	-148.3	-207.0
1982	0.0	1641.1	0.0	0.0	-1438.9	-1645.9
1983	0.0	2255.1	0.0	0.0	-1854.7	-3500.6
1984	0.0	697.4	0.0	0.0	-337.1	-3837.8
1985	86.5	509.7	415.4	4448.7	1768.1	-2069.7
1986	128.1	262.5	448.6	7116.0	3145.5	1075.8
1987	155.5	279.9	484.5	9326.9	4024.1	5099.9
1988	162.4	0.0	523.3	10520.3	2854.2	7954.1
1989	146.4	0.0	565.1	10243.6	2769.7	10723.8
1990	124.1	0.0	610.3	9377.0	2545.9	13269.7
1991	105.5	0.0	659.1	8609.9	2337.6	15607.2
1992	89.8	0.0	711.9	7915.0	2125.2	17732.4
1993	76.3	0.0	768.8	7263.0	1926.9	19659.3
1994	64.9	0.0	830.3	6671.7	1746.8	21406.1
1995	55.1	0.0	896.8	6117.7	1574.4	22980.5
1996	47.1	0.0	968.5	5647.8	1399.7	24380.2
1997	39.8	0.0	1046.0	5154.1	1216.2	25596.4
1998	33.6	0.0	1129.7	4699.3	1043.0	26639.4
1999	29.8	0.0	1220.0	4501.3	947.4	27586.8
2000	28.0	0.0	1317.6	4567.6	931.6	28518.4
2001	27.8	0.0	1423.1	4897.8	994.8	29513.2
2002	24.5	0.0	1536.9	4661.9	878.8	30392.0
2003	22.0	0.0	1659.9	4521.0	789.0	31181.0
2004	19.4	0.0	1792.6	4305.6	672.9	31853.9
2005	18.0	0.0	1936.1	4314.6	622.4	32476.2
2006	15.4	0.0	2090.9	3986.6	463.2	32939.4
TOTAL	1500.0	5947.7	23035.4	138866.8	32939.4	

TABLE 3:4:6
TYPICAL CASHFLOW TO OPERATOR
HIBERNIA OIL 1500 MM BBLS
($ CDN 1980 MILLIONS)

YEAR	PRODUCTION (mm bbls)	INVESTMENT	OPER. COST	REVENUE	NET CASHFLOW	CUMULATIVE CASHFLOW
1980	0.0	134.0	0.0	0.0	-58.7	-58.7
1981	0.0	155.6	0.0	0.0	-137.3	-196.0
1982	0.0	1407.0	0.0	0.0	-1233.7	-1429.7
1983	0.0	1790.2	0.0	0.0	-1472.3	-2902.0
1984	0.0	512.6	0.0	0.0	-247.8	-3149.8
1985	86.5	346.9	282.7	3027.7	1203.4	-1946.5
1986	128.1	165.4	282.7	4484.3	1982.2	35.7
1987	155.5	163.3	282.7	5442.2	2348.0	2383.8
1988	162.4	0.0	282.7	5683.8	1542.0	3925.8
1989	146.4	0.0	282.7	5124.4	1385.5	5311.3
1990	124.1	0.0	282.7	4343.4	1179.3	6490.6
1991	105.5	0.0	282.7	3692.6	1002.5	7493.1
1992	89.8	0.0	282.7	3143.2	843.9	8337.1
1993	76.3	0.0	282.7	2670.6	708.5	9045.6
1994	64.9	0.0	282.7	2271.5	594.7	9640.3
1995	55.1	0.0	282.7	1928.6	496.3	10136.6
1996	47.1	0.0	282.7	1648.5	408.6	10545.2
1997	39.8	0.0	282.7	1393.0	328.7	10873.9
1998	33.6	0.0	282.7	1176.0	261.0	11134.9
1999	29.8	0.0	282.7	1043.0	219.5	11354.4
2000	28.0	0.0	282.7	980.0	199.9	11554.3
2001	27.8	0.0	282.7	973.0	197.6	11751.9
2002	24.5	0.0	282.7	857.5	161.6	11913.6
2003	22.0	0.0	282.7	770.0	134.4	12047.9
2004	19.4	0.0	282.7	679.0	106.1	12154.1
2005	18.0	0.0	282.7	630.0	90.9	12244.9
2006	15.4	0.0	282.7	539.0	62.6	12307.6
TOTAL	1500.0	4675.0	6219.4	52501.3	12307.6	

Table 3:4:7

Platform Superstructure and Substructure Costs Escalation

	Superstructure Escalation	
Year	United Kingdom Sector	Norwegion Sector
1971	11%	9%
1972	6%	7%
1973	6%	13%
1974	22%	23%
1975	17%	13%

	Substructure Escalation	
Year	United Kingdom Sector	Norwegion Sector
1971	20%	18%
1972	3%	12%
1973	9%	23%
1974	22%	24%
1975	6%	12%

Source: Harald A. Ashiem, Augusto L. Podio and Roy M. Knapp, "Costs Correlated for North Sea Platforms", Oil and Gas Journal, May 5, 1980, P. 206.

4. THE EFFECTS OF ALTERNATE PRICING POLICIES ON HIBERNIA PROFITABILITY

4.1 Current Pricing Policies

Under current pricing policies, the price received by a producer for oil from offshore Newfoundland (e.g. Hibernia) would be the Canadian price adjusted for quality and in accordance with transportation differentials. This would be true whether Hibernia crude were to be consumed domestically or exported to markets outside Canada.

The most important single factor in understanding the price system in the international petroleum market is the existence of the strong producer cartel, OPEC. From 1973 to 1978, the international price of oil was set collectively by the OPEC countries and during that period the Persian Gulf price (i.e. Arabian Light) was the reference point for the world (non-Communist) oil pricing patterns. Since 1978, there has been some weakening in the cohesiveness of OPEC's pricing policies and, hence, a move away from a one price system. There are presently three different levels of OPEC crude oil prices: (1) a so-called moderate line, advanced primarily by Saudi Arabia; (2) a more aggressive line, advanced by the more agressive OPEC members; and (3) the spot market price, representing a small percentage of sales.

It is extremely difficult to forecast international crude oil price levels. Many factors and extreme uncertainties enter the equations. Iran and Saudi Arabia hold the key to the short term future. The long term outlook for oil prices is indicated by the Ministerial Committee on Strategy set up by OPEC in 1978, which favors regular increases in the price. Most analysts agree that the critical factor will be the continued cohesiveness and, hence, strength of the OPEC cartel.

The average wellhead price of crude oil produced in Canada and sold for domestic consumption is currently $14.75 per barrel. This is in the order of $20.00 per barrel below international crude oil price levels. The margin between the international price and Canadian price for domestic consumption is now wider than ever before, including 1973. This is illustrated in Figure 4:1:1. These low crude prices provide Canadian consumers with the lowest petroleum product prices of any major industrialized country.

The present price structure is maintained through a system of import subsidies and export tariffs and through the artificially low price of domestically produced crude. A refiner importing oil for consumption within Canada receives a subsidy from the federal government sufficient to reduce the cost of such imports to that of the Canadian price. Domestically produced oil exported to foreign markets is raised to the international price level by the federally imposed export tax. The federal government has in essence two resulting cashflow streams - one positive from Canadian exports of oil, a second negative to Canadian refiners importing oil for domestic consumption.

The balance of oil imports and oil exports is of critical importance to the federal government in terms of budgeting and financial implications. Presently, exports are less than imports; thus, the federal treasury is in a correspondingly negative cashflow position.

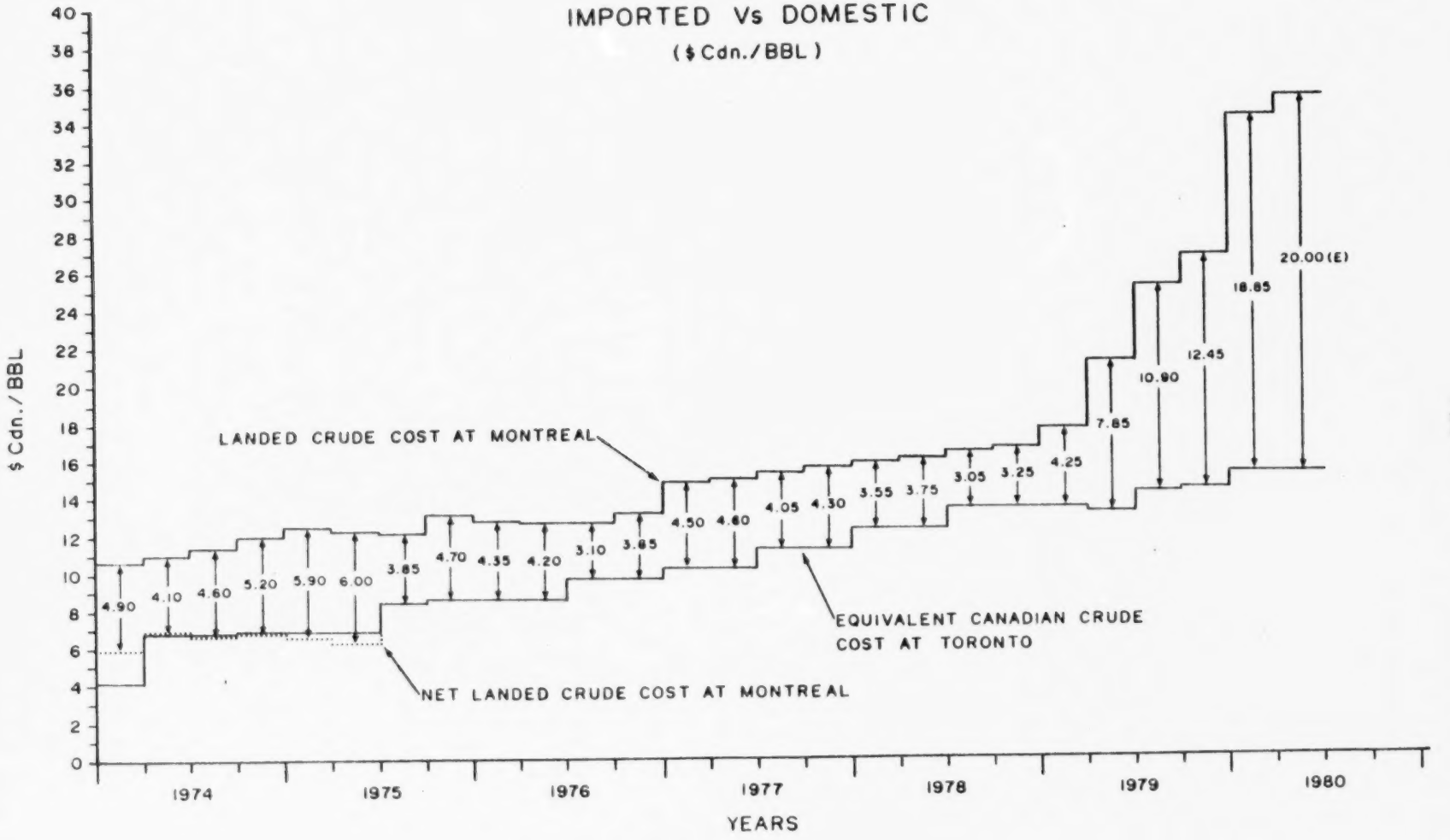
Canada's future pricing policy is clouded by uncertainty. Likely future price levels for domestic crude oil sales are, therefore, difficult to forecast. Only the direction is certain. It is unlikely that Canadian prices can go anywhere but up. It is also probably safe to say that the gap between the international and domestic price cannot, as over the past several years, continue to widen.

Figure 4:1:1

CRUDE OIL PRICES

IMPORTED Vs DOMESTIC

($ Cdn./BBL)



Source: Federal Department of Energy, Mines and Resources, Oil Supply Background, 1980.

In policy statements going back over some time, the Government of Newfoundland and Labrador has recognized the need for the Canadian price of oil to be more in line with international price levels. Newfoundland also recognizes the need to preserve the concept of a Canadian price that would in effect be below the international prices and would thereby provide an advantage to domestic consumers. The Government of Newfoundland and Labrador suggests a consumer premium as much as 10% below international price.* The pricing scenarios assumed for purposes of this analysis are as follows:

1) Canadian price at 90% of international price and escalated at 8% per year;
(2) present Canadian price escalated at $4.00 per year; and
(3) present Canadian price escalated at $2.00 per year.

These three scenarios represent the ranges of possible pricing policies likely to apply to the Hibernia development. The provincial policy of 90% of international prices should be viewed as a reasonable position that the province is willing to take on the assumption that the question of offshore ownership and control can be settled satisfactorily. If, however, the profitability of offshore developments drops below acceptable levels, reconsideration of this position would be entertained in order to make the development of marginal oil fields possible. In the view of the province, the 90% formula should be applied to all frontier developments. The province cannot accept, for instance, that "Federal" oil in the Beaufort Sea is to be developed on the basis of international prices, while oil developed in the province would have a lower price apply to it.

4.2 Effects on Hibernia Cashflows

Offshore Newfoundland and Labrador is a high cost environment for exploration and development. Consequently recoverable reserves and well productivity must be much higher than normal for industry if commercial production is to be possible. By the same token, the price received for the product is of considerable importance in the commercial viability of the project.

Table 4:2:1 gives the net cashflow for the Hibernia field under four alternate price assumptions at the 25% discount rate for the 500 million barrel reserves case. Tables 4:2:2 and 4:2:3 present the same figures for the 1,000 and 1,500 million barrel reserves cases, respectively. The 25% discount rate was chosen as the probable minimum internal rate of return for the operation. Since these cashflows are based upon current dollars, the 25% rate of return in fact represents a 17% rate of return in constant 1980 dollars. This rate of return is undoubtedly a minimum in a high risk/high cost environment such as offshore Newfoundland and Labrador.

Internal rates of return for the Hibernia field development are presented in the above tables in order to illustrate the relative attractiveness of each price assumption to the operation under the three reserves cases.

There are at least two points worthy of highlight. Firstly, at the 25% discount rate, no reserves category analyzed is sufficiently profitable to generate a positive net cashflow under the assumption of Canadian price escalated at $2.00 per year.

Secondly, in several of the net cashflow scenarios, negative figures are evident in the last years of production (note particularly the annual net cashflows for the 1,500 million barrel

* In policy statements (see the statement by the Hon. A. Brian Peckford at the Federal/Provincial First Ministers Conference on Energy Issues, Nov. 27, 1979), reference was made to a consumer premium at 10% below the "Chicago Price". The United States is firmly committed to a policy permitting the American domestic price to rise to that of international levels by Sept., 1981.

Table 4:2:1

Net Cashflow to the Operators Under Alternate Pricing Policies
For the 500 mm bbls Reserves Case
($ Millions @ 25% Discount Rate)

Year	100% of International Price	90% of International Price	Can. Esc. @ $4./yr.	Can. Esc. @ $2./yr.
1980	-58.7	-58.7	-58.7	-58.7
1981	-90.0	-90.0	-90.0	-90.0
1982	-637.9	-637.9	-637.9	-637.9
1983	-642.8	-642.8	-642.8	-642.8
1984	-101.7	-101.7	-101.7	-101.7
1985	165.4	138.6	85.1	44.8
1986	273.7	241.6	183.7	128.3
1987	295.1	261.4	205.2	141.2
1988	282.6	252.0	204.9	141.2
1989	213.2	189.5	152.2	101.1
1990	89.6	132.0	104.5	65.9
1991	63.9	56.2	72.5	43.0
1992	44.4	38.7	48.3	26.4
1993	34.5	30.0	21.6	18.4
1994	26.5	23.0	15.8	12.3
1995	21.5	18.5	12.2	8.7
1996	15.8	13.5	8.2	4.8
1997	11.7	9.9	5.5	2.3
1998	8.4	7.0	3.3	0.4
1999	5.5	4.5	1.6	-1.1
2000	4.0	3.2	0.7	-1.7
TOTAL	24.7	-111.4	-406.0	-795.0
Internal Rate of Return*	25%	23%	18%	10%

*Rounded to the nearest percent.

Table 4:2:2

Net Cashflow to the Operators Under Alternate Pricing Policies
For the 1000 mm bbls Reserves Case
($ Millions @ 25% Discount Rate)

Year	100% of International Price	90% of International Price	Can. Esc. @ $4./yr.	Can. Esc. @ $2./yr.
1980	-58.7	-58.7	-58.7	-58.7
1981	-90.0	-90.0	-90.0	-90.0
1982	-711.6	-711.6	-711.6	-711.6
1983	-705.8	-705.8	-705.8	-705.8
1984	-113.8	-113.8	-113.8	-113.8
1985	429.6	376.5	270.5	167.4
1986	573.9	511.7	399.7	265.3
1987	594.8	530.3	422.5	271.5
1988	337.8	302.6	411.0	266.1
1989	260.1	232.5	189.3	197.4
1990	188.8	168.4	136.0	136.7
1991	137.8	122.6	97.6	56.7
1992	99.8	88.5	69.0	38.4
1993	72.4	64.1	48.5	25.7
1994	51.6	45.5	33.2	16.4
1995	40.1	35.2	24.7	11.6
1996	31.5	27.6	18.5	8.1
1997	21.5	18.7	11.7	4.3
1998	16.0	13.8	8.0	2.4
1999	13.8	11.9	6.5	1.8
2000	10.3	8.8	4.3	0.7
2001	7.6	6.5	2.7	0.0
2002	5.6	4.7	1.6	-0.4
TOTAL	1212.9	890.0	475.4	-209.8
Internal Rate of Return*	38%	35%	30%	22%

*Rounded to the nearest percent.

Table 4:2:3

Net Cashflow to the Operators Under Alternate Pricing Policies
For the 1500 mm bbls Reserves Case
($ Millions @ 25% Discount Rate)

Year	100% of International Price	90% of International Price	Can. Esc. @ $4./yr.	Can. Esc. @ $2./yr.
1980	-58.7	-58.7	-58.7	-58.7
1981	-118.7	-118.7	-118.7	-118.7
1982	-920.9	-920.9	-920.9	-920.9
1983	-949.6	-949.6	-949.6	-949.6
1984	-138.1	-138.1	-138.1	-138.1
1985	579.4	506.4	360.8	219.1
1986	824.6	734.5	572.3	377.7
1987	843.9	752.0	598.2	382.9
1988	478.9	429.1	583.6	379.0
1989	371.7	332.5	271.1	283.9
1990	273.4	244.0	197.5	119.9
1991	200.8	178.9	142.7	83.6
1992	146.0	129.8	101.5	57.2
1993	105.9	93.9	71.4	38.4
1994	76.8	67.8	49.9	25.4
1995	55.4	48.7	34.3	16.2
1996	39.4	34.5	23.0	9.8
1997	27.4	23.8	14.7	5.3
1998	18.8	16.2	9.0	2.3
1999	13.7	11.6	5.8	0.7
2000	10.7	9.1	4.0	0.0
2001	9.2	7.8	3.1	-0.2
2002	6.5	5.4	1.6	-0.8
2003	4.7	3.8	0.7	-1.1
2004	3.2	2.5	0.1	-1.3
2005	2.4	1.8	-0.3	-1.3
2006	1.4	1.0	-0.6	-1.4
TOTAL	1980.1	1449.3	858.5	-190.7
Internal Rate of Return*	40%+	37%	32%	22%

* Rounded to the nearest percent.

case for all price assumptions except the 100% and 90% of international price scenarios). Because production would not occur in these years, reserves which are economically recoverable at either 100% or 90% of international price levels become uneconomic at the Canadian price escalated at either $4.00 or $2.00 per year. The greater the divergence between international and Canadian price levels, the lower the recoverable reserves become, if the three pricing scenarios are rigidly applied.

The conclusions arising from this analysis may be summarized as follows:

1. Price increases of $2.00 per year would make Hibernia uneconomic.

2. Price increases of $4.00 per year would make Hibernia unattractive because the financial institutions would consider the low rate of return on the 500 million barrels reserves case an unacceptable risk since no production experience exists in this area. Even if reserves are eventually proven to be 1,000 million barrels, the probability of actually recovering considerably less must be taken into account. In addition, the international oil industry might not, in this case, assign the Hibernia development the necessary urgency that is required in order to achieve Canadian self-sufficiency in view of the unfavorable economic environment in comparison with other worldwide opportunities.

3. 90% of international prices would make Hibernia marginally attractive in this high risk environment.

4. Only international prices would make Hibernia a truly attractive investment.

4.3 Effects on Full Cycle Rate of Return

It is unfair to consider the effects of alternate pricing policies solely on the basis of cashflows from the discovered field. The oil companies have accepted considerable geological risk related to the drilling of 140 offshore wells along the Canadian east coast. The rate of return to the oil industry must include an acceptable return for taking these geological risks. A number of these dry holes, costing as much as $30 million each, have to be included in the overall analysis before a true rate of return to the oil industry can be established. This type of analysis, recognizing the probability of various outcomes, is called the full cycle rate of return.

By the same token, Canada's favorable tax policy, including the beneficial depletion allowance with regard to the write-off provisions for dry hole costs, has to be taken into account as well in the full cycle rate of return analysis.

The full cycle in the example used here is constructed by taking the three reserves cases and combining these with the possibility of a dry hole outcome assuming the following probabilities:

Dry hole	- 0.950 probability;
500 million bbls.	- 0.035 probability;
1,000 million bbls.	- 0.010 probability;
1,500 million bbls.	- 0.005 probability.

This probability assessment attempts to parallel the analysis undertaken by the oil company prior to drilling and its assessment of the probable outcome of its exploration effort.

The 0.95 probability of drilling a dry hole equates to a 1 in 20 chance of making a commercial discovery. This probability assumed here represents a very optimistic assessment of risk associated with exploration in this area. In reality, the geological risk

may have been perceived to be higher in the east coast offshore area before the Hibernia discovery.

Table 4:3:1 presents the effects on full cycle rate of return of each of the three alternative pricing scenarios. Clearly, the effects are significant: a full cycle rate of return of 25%, assuming the 90% of international price scenario, falls to 21% under the Canadian price escalated at $4.00 per year and to 13% under the Canadian price escalated at $2.00 per year.

Table 4:3:1

Effects of Various Pricing Assumptions
On Full Cycle Rate of Return

Pricing Assumption	Rate of Return
90% of international price	25.0%
Canadian Price @ $4.00/yr.	21.0%
Canadian Price @ $2.00/yr.	13.0%

It is provincial policy, where possible, to recognize the need for an operator's full cycle rate of return to be at least 25%. This principle is embodied in the Newfoundland and Labrador Petroleum Regulations such that, when a company does not obtain a rate of return of 25%, the additional sliding scale royalty can be adjusted to a level where cashflow is sufficient to accomplish the 25% level. It is our understanding that this is also the implied federal position since the incremental royalty proposed in Bill C-20 only applies over and above a rate of return of 25%.

Only the provincial position of maintaining prices at 90% of international levels would provide a full cycle rate of return which would meet the 25% level considered acceptable, and would guarantee a healthy ongoing exploration activity. The $4.00 per barrel annual increase might seriously impede future exploration activities. Under the $2.00 per barrel annual increase, the rate of return falls far short of the required level of 25% and will likely result in curtailment of exploration activities.

4.4 Effects of Pricing Policies on Subsequent Developments

So far, we have been discussing the question of the effects of pricing policies on Hibernia development. It is also important to analyze the effects each of the three alternate pricing policies might have on subsequent developments in the area offshore Newfoundland and Labrador. If Canada is to achieve the goal of self-sufficiency in oil products, it is essential that public policy regarding pricing, resource taxation, or whatever not be a deterrent to exploration and development activities in the offshore. Indeed, public policy should encourage exploration and development in a high potential area such as offshore Newfoundland and Labrador.

The example of a subsequent (or future) development used for the analysis in this section is a development similar in size and cost to Hibernia but one discovered five years later and developed in a time frame similar to Hibernia.

Table 4:4:1 presents the effects of the three pricing policies on such a development. The full cycle rates of return under the pricing levels of 90% of international price, present Canadian price escalated at $4.00 per year, and present Canadian price escalated at $2.00 per year are 21%, 16% and 5%, respectively. This compares with the full cycle rates of return of 25%, 21% and 13%, respectively, for Hibernia at the beginning of 1980 (Compare with Table 4:3:1).

Table 4:4:1

Effects of Various Pricing Assumptions
on Subsequent Developments
(1000 mm bbls. Reserves)

Pricing Assumption	Rate of Return
90% of international price	21%
Canadian Esc. @ $4./yr.	16%
Canadian Esc. @ $2./yr.	5%

Interest in exploration may rapidly deteriorate if international prices do not increase substantially over general inflation and approach levels of at least offshore cost escalation (which we assumed at a somewhat conservative level of 12%). This is especially the case with the $2.00 per year increase scenario, which would result in a complete halt to offshore exploration in very few years. A policy aimed at a $4.00 per year price increase cannot be maintained for more than a few years if an adequate level of East Coast exploration is to be pursued as a policy objective, as we maintain it should. The $4.00 per year policy would not lead to self-sufficiency in oil because frontier exploration and development cost escalation would rapidly make future developments unprofitable.

5. REVENUE SHARING: NEWFOUNDLAND AND LABRADOR PETROLEUM REGULATIONS VERSUS THE MARITIME AGREEMENT

5.1 Review of the Provincial and Federal Positions

In the preceding sections, only cashflows to the operator from the Hibernia development have been considered. In this section, we look at potential cashflows to the provincial and federal governments under the Newfoundland and Labrador Petroleum Regulations and the Maritimes Agreement. The 1,000 million barrels reserves case and the three price scenarios discussed previously are applied to both the provincial and the federal proposals.

5.1.1 Newfoundland and Labrador Petroleum Regulations

The Newfoundland and Labrador Petroleum Regulations came into effect in November, 1977.

The regulations require the operator to pay a basic royalty of 10% of net production and a sliding scale royalty based on the yearly net production from a lease area. In addition, it is to be a condition of every lease that the lessee shall transfer to the province an undivided interest of 40% in his lease within one year after its issuance.

Revenue to the province under the Newfoundland and Labrador Petroleum Regulations, therefore, will be of two types, royalty income and revenue from participation. The province would also receive normal corporate income tax from the project. It should be noted also that additional revenues would accrue to the federal government by way of excise tax, federal sales tax, etc. These additional revenues, however, are not taken into account in the analysis presented here.

Revenue to the federal government would be its share of corporate income tax.

5.1.2 Maritime Agreement

The federal proposal is embodied in the Maritime Agreement proposed to the provinces of New Brunswick, Nova Scotia and Prince Edward Island. Under the federal formula, there is a shared royalty and progressive incremental royalty (P.I.R.) split between the federal and provincial governments, with 25% of the revenues going to the federal government and 75% of the revenues to the provincial government. The province would receive no share of corporate income tax. The federal government would, in addition, receive a 25% interest in any production lease through participation by Petro-Canada. The actual revenue flows developed below are based on the assumption that federal land tenure legislation applies in the case of the Maritime Agreement and that the provisions of Bill C-20 have been brought into law.

5.2 Revenues Under the Newfoundland and Labrador Petroleum Regulations

Table 5:2:1 shows the flow of revenues, in constant 1980 Canadian dollars, to each of the two levels of government for the 1,000 million barrels reserves case assuming a price at 90% of the international level. Tables 5:2:2 and 5:2:3 show similar revenue flows but based on the Canadian price escalating at $4.00 per year and $2.00 per year, respectively.

Negative income tax appears in the years during development because it is assumed that the company has income elsewhere in Canada against which to write-off exploration and development expenditures.

Revenue to the federal government is generated from income tax which is assumed to remain at the present level of 36 percent over the life of the project.

The province's revenue comes from a combination of working (or earned)

Table 5:2:1

Government Revenue under the Newfoundland & Labrador Petroleum Regulations
Canadian Price @ 90% of International Price/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

	Provincial Government Revenue				Federal Government Revenue
Year	Govt. Part.	Royalties	Income Tax	Total	Income Tax
1980	0.0	0.0	-22.2	-22.2	-53.2
1981	0.0	0.0	-4.1	-4.1	-9.8
1982	0.0	0.0	-39.4	-39.4	-94.5
1983	0.0	0.0	-70.6	-70.6	-169.4
1984	0.0	0.0	-59.4	-59.4	-142.6
1985	0.0	201.4	146.8	348.2	352.3
1986	0.0	315.4	245.3	560.7	588.8
1987	0.0	403.3	319.7	723.0	767.3
1988	1122.7	429.2	208.7	1760.5	500.9
1989	1006.0	377.7	189.0	1572.7	453.5
1990	845.3	306.8	159.3	1311.3	382.2
1991	712.6	248.2	134.4	1095.2	322.5
1992	594.7	196.2	111.9	902.8	268.5
1993	498.7	162.2	94.0	755.0	225.6
1994	411.4	138.0	78.0	627.4	187.2
1995	370.6	126.6	70.6	567.8	169.5
1996	366.5	117.2	64.4	518.0	154.5
1997	266.3	97.7	51.3	415.2	123.2
1998	228.8	87.3	44.4	360.5	106.5
1999	227.7	86.9	44.2	358.8	106.1
2000	196.0	78.1	38.3	312.3	91.8
2001	167.6	70.2	33.0	270.8	79.2
2002	142.7	63.3	28.3	234.3	68.0
TOTAL	7127.5	3505.8	1865.9	12499.1	4478.1

Table 5:2:2

Government Revenues under the Newfoundland & Labrador Petroleum Regulations
Canadian Price Escalated @ $4.00 per year/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

	Provincial Government Revenue				Federal Government Revenue
Year	Govt. Part.	Royalties	Income Tax	Total	Income Tax
1980	0.0	0.0	-22.2	-22.2	-53.2
1981	0.0	0.0	-4.1	-4.1	-9.8
1982	0.0	0.0	-39.4	-39.4	-94.5
1983	0.0	0.0	-70.6	-70.6	-169.4
1984	0.0	0.0	-59.4	-59.4	-142.6
1985	0.0	156.7	98.5	255.2	236.5
1986	0.0	252.3	184.8	437.1	443.5
1987	0.0	328.6	251.4	580.1	603.5
1988	0.0	353.3	279.3	632.6	675.1
1989	815.9	311.9	152.4	1280.3	365.9
1990	681.1	252.6	127.9	1061.6	307.0
1991	566.5	202.8	106.6	875.9	255.9
1992	463.4	158.3	87.2	708.9	209.2
1993	378.3	128.8	71.4	578.5	171.4
1994	301.2	107.4	57.4	466.0	137.7
1995	261.4	96.3	50.2	407.9	120.4
1996	227.3	86.9	43.9	358.1	105.4
1997	168.1	70.4	32.9	271.4	79.0
1998	134.3	61.0	26.7	222.0	64.0
1999	126.5	58.8	25.2	210.6	66.5
2000	98.6	51.1	20.0	169.7	48.0
2001	74.2	44.3	15.5	134.0	37.1
2002	53.1	38.5	11.6	103.1	27.7
TOTAL	4350.0	2760.0	1447.3	8557.3	3473.5

Table 5:2:3

Government Revenues under the Newfoundland & Labrador Petroleum Regulations
Canadian Price Escalated @ $2.00 per Year/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

	Provincial Government Revenue				Federal Government Revenue
Year	Govt. Part.	Royalties	Income Tax	Total	Income Tax
1980	0.0	0.0	-22.2	-22.2	-53.2
1981	0.0	0.0	-4.1	-4.1	-9.8
1982	0.0	0.0	-39.4	-39.4	-94.5
1983	0.0	0.0	-70.6	-70.6	-169.4
1984	0.0	0.0	-59.4	-59.4	-142.6
1985	0.0	113.2	51.6	164.8	123.9
1986	0.0	176.6	112.1	288.8	269.1
1987	0.0	224.1	155.9	379.9	374.1
1988	0.0	235.6	172.8	408.4	414.8
1989	0.0	203.9	154.2	358.1	370.1
1990	0.0	162.4	126.0	288.5	302.5
1991	327.5	128.4	61.3	517.2	147.1
1992	257.6	99.0	48.4	405.0	116.2
1993	201.0	79.5	38.2	318.8	91.6
1994	150.9	65.6	29.2	245.7	70.0
1995	124.6	58.3	24.5	207.4	58.8
1996	102.2	52.1	20.5	174.8	49.1
1997	65.5	41.9	13.7	121.1	32.9
1998	44.5	36.0	9.8	90.3	23.5
1999	39.0	34.5	8.8	82.4	21.2
2000	22.0	29.8	5.6	57.4	13.6
2001	7.2	25.7	2.9	35.8	7.0
2002	-5.4	22.2	0.6	17.3	1.4
TOTAL	1336.8	1788.8	840.5	3966.2	2017.3

interest in the lease area, royalties, and corporate income tax (assumed to be 15% over the life of the project). The largest percentage of the province's take comes from its participation or earned income. Revenue from participation does not begin until 1988, eight years after discovery and three years after production begins. Royalties and positive flows of income tax would begin in the first year of production. The revenue peak would be reached in 1988 and revenue would rapidly decrease thereafter.

5.3 Revenues Under the Maritime Agreement

Tables 5:3:1 to 5:3:3 show the flow of revenues to each of the two levels of government under the Maritime Agreement at the three price scenarios assumed earlier. All revenue figures are in constant 1980 dollars.

The progressive incremental royalty (P.I.R.) and the basic royalty are divided on the basis of 75 percent to the province and 25 percent to the federal government. The province would receive no corporate income tax (the federal rate would, therefore, be 46%) and the federal government would receive additional income via its participatory rights through Petro-Canada.

All revenue sources would begin at the start of production. Income tax, followed by participation income, would represent the federal government's largest revenue sources. The largest revenue resource to the province would be royalty income. This, however, would never reach significant proportions. Note that the progressive incremental royalty (P.I.R.) to both governments would disappear under the $2.00 per year price increase scenario. This is because a 25% internal rate of return would not be achieved.

5.4 Revenue Sharing Comparisons

This section compares the revenue sharing under the federal and provincial proposals. Table 5:4:1 presents the percentage divisions of government take under the Newfoundland and Labrador Petroleum Regulations and the Maritime Agreement for the three price scenarios assumed.

The Newfoundland and Labrador Petroleum Regulations, under the 90% of international price case, result in a split in revenue of 26.4% to the federal government and 73.6% to the provincial government. Under the Maritime Agreement, the percentage split is almost exactly reversed at 25% for the province and 75% for the Federal Government. At the time of the signing of the Maritime Agreement, it was the stated intention of the federal government to retain 25% of the revenue flows. The application of the Maritime Agreement and the principle of federal ownership and control do not achieve the 75% provincial, 25% federal split. The Newfoundland and Labrador Petroleum Regulations, however, do achieve this split. If it was the honest intention of the federal government at the time of signing of the Maritime Agreement to award the province 75% of all revenues generated in offshore development, then we see no reason why the federal government cannot accept the revenue provisions of the Newfoundland and Labrador Petroleum Regulations.

A further point is also important here. We have seen in earlier sections that the internal rate of return decreases among the three alternative pricing policies analyzed. We see that the percentage split in revenue under both the Newfoundland and Labrador Petroleum Regulations and the Maritime Agreement change significantly between pricing regimes, that is, the province's percentage take decreases as the

Table 5:3:1

Government Revenues Under The Maritime Agreement
Canadian Price @ 90% of International Price/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

	Provincial Government Revenue			Federal Government Revenue				
Year	P.I.R.*	Royalties Oil	TOTAL	Govt. Part.	P.I.R.	Royalties Oil	Income Tax	TOTAL
1980	0.0	0.0	0.0	-16.5	0.0	0.0	-67.9	-84.5
1981	0.0	0.0	0.0	-26.4	0.0	0.0	-12.6	-39.0
1982	0.0	0.0	0.0	-241.6	0.0	0.0	-120.7	-362.3
1983	0.0	0.0	0.0	-279.4	0.0	0.0	-216.4	-495.9
1984	0.0	0.0	0.0	-56.0	0.0	0.0	-182.3	-238.3
1985	0.0	144.8	144.8	209.8	0.0	48.3	450.2	708.2
1986	0.0	201.8	201.8	339.6	0.0	67.3	752.4	1159.2
1987	79.7	245.8	325.4	387.9	26.6	81.9	980.4	1476.8
1988	197.7	258.7	456.4	390.1	65.9	86.2	1066.8	1609.0
1989	228.4	232.9	461.4	327.9	76.1	77.6	965.9	1447.6
1990	199.0	197.5	396.5	269.3	66.3	65.8	814.1	1215.5
1991	171.8	168.2	340.0	222.4	57.3	56.1	686.7	1022.5
1992	142.4	142.2	284.6	182.9	47.5	47.4	571.9	849.7
1993	121.0	121.7	242.7	151.3	40.3	40.6	480.4	712.6
1994	98.1	103.5	201.6	124.7	32.7	34.5	398.7	590.2
1995	94.0	95.0	188.9	110.0	31.3	31.7	361.0	534.3
1996	90.6	87.9	178.5	97.8	30.2	29.3	329.1	486.1
1997	68.4	73.2	141.7	78.0	22.8	24.4	262.3	387.6
1998	59.8	65.4	125.2	66.4	19.9	21.8	226.8	334.9
1999	66.5	65.2	131.7	63.7	22.2	21.7	225.4	333.4
2000	57.9	58.6	116.5	54.3	19.3	19.5	195.6	288.7
2001	49.8	52.7	102.5	46.0	16.6	17.8	168.6	248.8
2002	42.4	47.5	89.9	38.8	14.1	15.8	144.8	213.6
TOTAL	1767.5	2362.6	4130.1	2541.1	589.2	787.5	8481.4	12399.2

*P.I.R. = Progressive incremental royalty

Table 5:3:2

Government Revenues Under The Maritime Agreement
Canadian Price Escalated @ $4.00 Per Year/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

	Provincial Government Revenue			Federal Government Revenue				
Year	P.I.R.*	Royalties Oil	TOTAL	Govt. Part.	P.I.R.	Royalties Oil	Income Tax	TOTAL
1980	0.0	0.0	0.0	-16.5	0.0	0.0	-67.9	-84.5
1981	0.0	0.0	0.0	-26.4	0.0	0.0	-12.6	-39.0
1982	0.0	0.0	0.0	-241.6	0.0	0.0	-120.7	-362.3
1983	0.0	0.0	0.0	-279.4	0.0	0.0	-216.4	-495.9
1984	0.0	0.0	0.0	-56.0	0.0	0.0	-182.3	-238.3
1985	0.0	112.6	112.6	150.3	0.0	37.5	302.2	490.1
1986	0.0	161.4	161.4	264.9	0.0	53.8	566.7	885.4
1987	0.0	200.3	200.3	330.2	0.0	66.8	771.1	1168.1
1988	96.3	213.0	309.2	339.4	32.1	71.0	856.5	1299.0
1989	138.3	192.4	330.7	282.9	46.1	64.1	779.2	1172.3
1990	121.6	162.6	284.3	230.6	40.5	54.2	653.7	979.1
1991	103.4	137.4	240.8	188.2	34.5	45.8	545.0	813.5
1992	81.4	114.8	196.2	152.4	27.1	38.3	445.5	663.3
1993	65.3	96.6	161.8	123.4	21.8	32.2	365.0	542.3
1994	47.2	80.5	127.7	99.3	15.7	26.8	293.2	435.0
1995	43.5	72.2	115.7	84.8	14.5	24.1	256.4	379.8
1996	40.1	65.2	105.2	72.6	13.4	21.7	224.5	332.2
1997	23.0	52.8	75.8	55.3	7.7	17.6	168.3	248.8
1998	16.1	45.8	61.8	44.5	5.4	15.3	36.2	201.4
1999	19.7	44.1	63.9	40.3	6.6	14.7	128.9	190.5
2000	12.9	38.3	51.2	31.8	4.3	12.8	102.3	151.1
2001	6.6	33.2	39.8	24.4	2.2	11.1	79.1	116.7
2002	1.0	28.8	29.9	18.1	0.3	9.6	59.0	87.1
TOTAL	816.4	1852.0	2668.4	1913.6	272.1	617.3	6132.8	8934.8

*P.I.R. = Progressive incremental royalty

Table 5:3:3

Government Revenues Under The Maritime Agreement
Canadian Price Escalated @ $2.00 Per Year/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

	Provincial Government Revenue			Federal Government Revenue				
Year	P.I.R.*	Royalties Oil	TOTAL	Govt. Part.	P.I.R.	Royalties Oil	Income Tax	TOTAL
1980	0.0	0.0	0.0	-16.5	0.0	0.0	-67.9	-84.5
1981	0.0	0.0	0.0	-26.4	0.0	0.0	-12.6	-39.0
1982	0.0	0.0	0.0	-241.6	0.0	0.0	-120.7	-362.3
1983	0.0	0.0	0.0	-279.4	0.0	0.0	-216.4	-495.9
1984	0.0	0.0	0.0	-56.0	0.0	0.0	-182.3	-238.3
1985	0.0	81.4	81.4	92.4	0.0	27.1	158.3	277.8
1986	0.0	113.0	113.0	175.3	0.0	37.7	343.9	556.8
1987	0.0	136.5	136.5	212.3	0.0	45.5	478.0	735.8
1988	0.0	142.0	142.0	240.2	0.0	47.3	530.0	817.5
1989	0.0	125.8	125.8	205.8	0.0	41.9	472.9	720.6
1990	0.0	104.6	104.6	163.7	0.0	34.9	386.5	585.1
1991	0.0	87.0	87.0	129.5	0.0	29.0	313.3	471.8
1992	0.0	71.7	71.7	100.0	0.0	23.9	247.6	371.4
1993	0.0	59.7	59.7	76.9	0.0	19.9	195.1	291.9
1994	0.0	49.2	49.2	57.1	0.0	16.4	149.1	222.6
1995	0.0	43.7	43.7	46.6	0.0	14.6	125.2	186.3
1996	0.0	39.1	39.1	37.7	0.0	13.0	104.6	155.4
1997	0.0	31.4	31.4	23.5	0.0	10.5	70.0	103.9
1998	0.0	27.0	27.0	15.3	0.0	9.0	50.1	74.4
1999	0.0	25.9	25.9	13.1	0.0	8.6	45.1	66.8
2000	0.0	22.3	22.3	6.5	0.0	7.4	28.9	42.8
2001	0.0	19.3	19.3	0.8	0.0	6.4	14.9	22.1
2002	0.0	16.6	16.6	-4.1	0.0	5.5	2.9	4.3
TOTAL	0.0	1196.2	1196.2	972.5	0.0	398.7	3116.3	4487.6

*P.I.R. = Progressive incremental royalty

operator's internal rate of return decreases, whereas the federal percentage increases. In other words, the Newfoundland and Labrador Petroleum Regulations are more sensitive to changes in profitability than the federal proposal.

Table 5:4:2 shows thr split of gross revenue (i.e. price received per barrel) between the company, the provincial and federal governments, and the consumer under the Newfoundland and Labrador Petroleum Regulations and the Maritime Agreement. The company share includes capital and operating costs.

Table 5:4:3 shows the percentage split of economic rent. These figures differ from those in Table 5:4:2 in that capital and operating costs have been netted out.

5.5 Effects on Equalization Entitlements

The equalization program is designed to ensure that all provinces are able to provide reasonably comparable levels of public services without resorting to unduly high levels of taxation. The program simply attempts to compensate each province for any deficiences in its fiscal capacity or its ability to raise revenue from provincial tax sources.

This section looks at the effects on equalization entitlement as a result of the potential development of the Hibernia oil field.

The present equalization formula expires in 1982, when it will be open to revision. However, for purposes of this paper, it is assumed that the current formula will remain unchanged for two more 5-year periods to 1992. Since it is very difficult to look even that far into the future, it is probably not very realistic to project beyond 1992.

Table 5:5:1 presents the revenue benefits to the provincial government from the Hibernia development net of the equalization losses that would occur as a result of this development under both the Newfoundland and Labrador Petroleum Regulations and the Maritime Agreement. The 1,000 million barrels reserves case combined with a Canadian price of 90% of the international price is assumed. By comparing the net revenue columns, it can be seen that, in all but the first three years after production begins, 1985-1987, the province would be in a net loss position if it were to accept the Maritime Agreement.

Tables 5:5:2 and 5:5:3 present the same comparison but under the scenarios of Canadian price escalated at $4.00 and $2.00 per year, respectively.

Equalization payments to the province without oil and gas are estimated to increase at approximately 10% per year, which, under an assumed inflation rate of 8% per year, represents a real increase of 2% per year. It can be seen from Tables 5:5:1 to 5:5:3 that, if Newfoundland receives revenue from the Hibernia development, it will lose some revenue under the equalization formulas.

The province takes the view that, since the choice is there, it would rather receive revenue from its own sources than get it as a result of equalization payments.

Equalization payments to the province under the Maritime Agreement would rise steadily over the period under review, although at a rate slightly below that of the case where no oil production is assumed.

Equalization payments to Newfoundland under the provincial regulations fall off rapidly within two to three years after production starts but begin to reappear in the last years of the study period as production tapers off. The losses in equalization payments are offset by revenues from royalties, taxes, etc., thereby resulting in a net revenue gain to the province as a result of Hibernia production.

Table 5:4:1

Government Revenue Sharing Comparisons
1000 mm bbls. Reserves Case
($ CDN 1980)

	Newfoundland and Labrador Petroleum Regulations		Maritime Agreement	
	% Prov. Take	% Fed. Take	% Prov. Take	% Fed. Take
90% of international price	73.6	26.4	25.0	75.0
Can. Esc. @ $4./yr.	71.1	28.9	23.0	77.0
Can. Esc. @ $2./yr.	66.3	33.7	21.0	79.0

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Table 5:4:2

Split of Gross Revenue
1000 mm bbls. Reserves Case

	Newfoundland & Labrador Petroleum Regulations		Maritime Agreement	
	$'s/bbl.	%	$'s/bbl.	%
Company	14.52	41	14.97	43
Provincial Gov't.	12.50	36	4.13	12
Federal Gov't.	4.48	13	12.40	35
Consumer	3.50	10	3.50	10
	35.00	100	35.00	100

Note: Calculations are based on constant 1980 dollars. The company and provincial and federal government shares are based on 90% of international price.

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Table 5:4:3

Percentage Split of Economic Rent
1000 mm bbls. Reserves Case
($ CDN 1980)

	Newfoundland & Labrador Petroleum Regulations	Maritime Agreement
Company	26%	27%
Provincial Gov't.	45%	15%
Federal Gov't.	16%	45%
Consumer	13%	13%
	100%	100%

Table 5:5:1

Comparison of Net Revenue to the Province from Hibernia
Under the Newfoundland & Labrador Petroleum Regulations & the Maritime Agreement
Canadian Price @ 90% of International Price/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

Year	Maritime Agreement				Nfld. & Lab. Petroleum Regulations		
	Equalization Revenue without Hibernia (1)	Equalization Revenue With Hibernia (2)	Prov. Revenue From Hibernia (3)	Net Additional Revenue (4) [(2+3)-1]	Equalization Revenue With Hibernia (5)	Prov. Revenue From Hibernia (6)	Net Additional Revenue (7) [(5+6)-1]
1980	379.0	379.0	-	-	379.0	-	-
1981	398.6	398.6	-	-	398.6	-	-
1982	407.8	407.8	-	-	407.8	-	-
1983	416.7	416.7	-	-	416.7	-	-
1984	423.8	423.8	-	-	423.8	-	-
1985	435.0	397.9	144.8	107.7	99.5	348.2	12.7
1986	446.4	406.1	201.8	161.5	-	560.7	105.4
1987	458.9	415.9	325.4	282.4	-	723.0	182.1
1988	469.9	424.8	456.4	411.3	-	1760.5	1036.1
1989	482.5	436.5	461.4	415.4	-	1572.7	923.3
1990	495.4	448.8	396.5	349.9	-	1311.3	758.3
1991	507.5	460.6	340.0	293.1	35.0	1095.2	622.7
1992	520.1	473.0	284.6	237.5	118.1	902.8	500.8

Table 5:5:2

Comparison of Net Revenue to the Province from Hibernia
Under the Newfoundland & Labrador Petroleum Regulations & the Maritime Agreement
Canadian Price Escalated at $4.00 per Year/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

Year	Maritime Agreement				Nfld. & Lab. Petroleum Regulations		
	Equalization Revenue Without Hibernia (1)	Equalization Revenue With Hibernia (2)	Prov. Revenue From Hibernia (3)	Net Additional Revenue (4) [(2+3)-1]	Equalization Revenue With Hibernia (5)	Prov. Revenue From Hibernia (6)	Net Additional Revenue (7) [(5+6)-1]
1980	379.0	379.0	-	-	379.0	-	-
1981	389.2	389.2	-	-	389.2	-	-
1982	400.4	400.4	-	-	400.4	-	-
1983	409.9	409.9	-	-	409.9	-	-
1984	417.1	417.1	-	-	417.1	-	-
1985	428.4	393.5	112.6	77.7	163.1	255.2	0.0
1986	438.5	400.3	161.4	123.2	75.7	437.1	71.3
1987	449.3	408.7	200.3	159.7	8.6	580.1	139.4
1988	461.0	417.3	309.2	265.5	-	636.8	172.7
1989	473.8	428.9	330.7	285.8	-	1280.3	749.9
1990	486.5	441.3	284.3	239.1	35.9	1061.6	611.0
1991	498.6	453.2	240.8	195.4	116.4	875.9	493.7
1992	511.0	465.8	196.2	151.0	190.0	708.9	387.9

Table 5:5:3

Comparison of Net Revenue to the Province from Hibernia
Under the Newfoundland & Labrador Petroleum Regulations & the Maritime Agreement
Canadian Price Escalated at $2.00 per year/1000 mm bbls Reserves Case
($ CDN 1980 Millions)

Year	Maritime Agreement			Nfld. & Lab. Petroleum Regulations		
	Equalization Revenue Without Hibernia (1)	Equalization Revenue With Hibernia (2)	Prov. Revenue From Hibernia (3)	Net Additional Revenue (4) [(2+3)-1]	Equalization Revenue With Hibernia (5)	Prov. Revenue From Hibernia (6)	Net Additional Revenue (7) [(5+6)-1]
1980	379.0	379.0	-	-	379.0	-	-
1981	387.3	387.3	-	-	387.3	-	-
1982	397.0	397.0	-	-	397.0	-	-
1983	405.1	405.1	-	-	405.1	-	-
1984	408.7	408.7	-	-	408.7	-	-
1985	416.9	385.2	81.4	49.7	224.8	164.8	-
1986	425.9	390.3	113.0	77.4	169.7	288.8	32.6
1987	435.9	397.9	136.5	98.5	135.4	379.9	79.4
1988	447.0	407.8	142.0	102.8	137.6	408.4	99.0
1989	459.4	420.3	125.8	86.7	184.0	358.1	82.7
1990	471.9	433.3	104.6	66.0	238.8	288.5	55.4
1991	484.0	446.3	87.0	49.3	247.7	517.2	280.9
1992	496.6	459.9	71.7	35.0	301.1	405.0	209.5

The significance of this "net revenue" gain should be viewed in the light of the province's current debt borrowing requirements as well as its per capita income disparity as compared with other more prosperous parts of Canada, e.g. Ontario.

Newfoundland's provincial tax rates are extremely high by comparison with those of Ontario despite the fact that the province's per capita income is lower. In 1978, Newfoundland's per capita income was 60.8 percent of that of Ontario's.

Despite the high tax rates, the province is continually forced to borrow capital in an attempt to provide provincial residents with an adequate standard of public services.

The province's borrowing over the last five years can be summarized as follows:

1974 - 75	$ 233.5 millions
1975 - 76	$ 270.3 millions
1976 - 77	$ 350.7 millions
1977 - 78	$ 251.5 millions
1978 - 79	$ 259.6 millions

The provincial borrowing program, although modest when considering the necessity of public services, has forced a continual increase in the direct debt of the province. In 1978, the per capita direct debt of Newfoundland was $3,283, or 211 percent of that of Ontario.

The debt requirements have saddled the province with sizable interest obligations and have imposed a constraint on the ability to upgrade public services to the level of the national average. Unfortunately, the development of the Hibernia oil field will probably not provide all of the funds necessary for the province to reduce the tax burden on provincial residents, eliminate the province's borrowing needs, reduce the level of provincial debt, and upgrade the standard of public services.

The development of an offshore oil field will increase the province's need to undertake various high cost capital projects and will result in raised expectations of local residents with respect to public services.

It is projected that, without Hibernia and the additional borrowing requirements made necessary by resulting infrastructure needs, the province's future borrowings will escalate at approximately 2 percent a year in constant dollar terms. Based upon this assumption, the projected borrowing requirements of the province for the years 1985 to 1992 are as follows:

1985	$297.5 millions
1986	$303.0 millions
1987	$309.0 millions
1988	$315.2 millions
1989	$321.5 millions
1990	$327.9 millions
1991	$334.5 millions
1992	$341.2 millions

By comparing the projected borrowing figures with the net revenue figures contained in Tables 5:5:1 to 5:5:3, one can see that only in the 90% of international price case and under the Newfoundland and Labrador Petroleum Regulations is the province better off and, then, not significantly. Net gain to the province under the Maritime Agreement would be inadequate to offset the present and anticipated borrowing needs of the province.

With respect to the potential revenues from Hibernia improving the per capita income in the province, one need only consider that Newfoundland's per capita income in 1978 was 60.8 percent of the per capita income of Ontario. If we make the somewhat generous assumption that, because of Hibernia, Newfoundland will achieve a rate of growth that surpasses that of Ontario by 2% in real terms, it will take 20 years for Newfoundland to be on a par with Ontario.

6. SEQUENCING OF DEVELOPMENTS

6.1 Provincial Proposal

In the White Paper of May, 1977, the Province of Newfoundland stressed the enormous importance of exercising control over the rate of offshore oil field development. The principle of controlled development is viewed by the Province as being of crucial importance in its overall development strategy and, as such, constitutes an important aspect of the province's petroleum regulations.

There are a number of geological structures in the area around Hibernia which could contain commercial quantities of oil and which could be developed either simultaneously or sequentially (as proposed by the provincial government). In recognizing the importance of sequencing, a key provision was incorporated into the Newfoundland and Labrador Petroleum Regulations such that, in any particular management zone, the Minister may delay the development of a second and subsequent petroleum field if such a delay is deemed to be in the interest of the province.

If a number of oil fields (for instance, three) were to be developed in sequence, the provincial economy would have the necessary lead time to adjust to the obvious opportunities. The skills demanded by the industry could be acquired and the necessary investments made so that the province could absorb the benefits of offshore developments over a reasonable period of time.

However, the simultaneous undertaking of several massive projects in a short time period and in a relatively small provincial economy would cause an undesirable, unnecessary and excessive amount of social and economic disruption. Without the appropriate lead time, the province's productive capacity could not be sufficiently expanded to take maximum advantage of the opportunities resulting from offshore development and, consequently, many of the benefits would be exported out of the province and the nation. The simultaneous development of several oil fields would also impose a critical strain on the province in areas such as the ability of the economy to deliver goods and services, the local labour market, the local society and culture, and the environment.

An uncontrolled rate of development would also have an adverse influence on indigenous industries, particularly the fishery, that represent a permanent basis for our prosperity after the temporary construction projects have ended and the nonrenewable petroleum fields are exhausted.

At the same time, the province recognized the importance to Canada - and especially eastern Canada - of an expeditious development of Newfoundland's offshore petroleum reserves. This factor has been accounted for in the provincial petroleum regulations, which link the sequencing mechanism and a volume of production which is far in excess of provincial needs.

6.2 Illustration of the Effect of Sequencing on the Economy

Table 6:2:1 provides an example of the investments required for three oil fields, Hibernia and two similar fields, under the assumptions of sequenced versus uncontrolled development. In this illustration, the assumption is that under a sequenced development pattern a new oil field would begin every four years whereas with an uncontrolled pattern a new oil field would begin in each of three successive years. On the basis of provincial regulations, the sequential pattern of development would produce ongoing activity for 16 years. In the uncontrolled boom, the development would only last 10 years.

The importance of the delay stems from two factors; namely, (1) the

Table 6:2:1

Total Annual Investment in the Exploration and Development of Three Hibernia Sized Oil Fields (in $ CDN 1980 millions)

Year	Sequenced Developments (Provincial Proposal)	Uncontrolled Developments (Federal Proposal)
1980	134	134
1981	118	257
1982	1087	1354
1983	1334	2588
1984	561	2959
1985	372	2091
1986	1355	779
1987	1641	452
1988	649	207
1989	430	105
1990	1568	
1991	1898	
1992	544	
1993	314	
1994	131	
1995	131	
	12,267	10,927

Table 6:2:2

Estimated Expenditures in the Province
Under the Sequenced and Uncontrolled Development Scenarios
($ CDN 1980 millions)

Year	Sequenced Developments (Provincial Proposal)	Uncontrolled Developments (Federal Proposal)
1980	15	15
1981	21	21
1982	30	30
1983	42	42
1984	60	60
1985	56	84
1986	84	118
1987	118	72
1988	97	31
1989	65	16
1990	165	
1991	231	
1992	81	
1993	48	
1994	20	
1995	20	
	1,153	489

province must have sufficient time to develop the necessary expertise and capacity to absorb offshore business, and (2) the maximum percentage that the province can currently capture from the total offshore business is probably limited to 20 percent.

To present an example of the probable maximum amount of expenditures in the province as a result of the development of three Hibernia-sized oil fields, the following two assumptions have been made:

(1) the provincial offshore industries would grow at a maximum rate of approximately 40 percent per year, and

(2) the maximum business obtainable is 20 percent of the total.

The expenditures in the province under the federal proposal and under the provincial proposal are presented in Table 6:2:2. In this particular example, the province would lose $644 million worth of employment-creating expenditures as a result of uncontrolled development.

The rate of oil field development will become of crucial importance if production equipment and facilities are to be assembled in the province. If the provincial business sector is given the opportunity to obtain the necessary expertise and capacity, an industry could be developed that would result in continuous large scale employment for many years.

6.3 Beneficial Impact on the Maritime Provinces

The preceding sections have noted that the Province of Newfoundland would benefit tremendously from an orderly development of the province's offshore resources. The Maritime provinces are in a similar position - the slower the pace of development, the greater their ability to adjust to the offshore opportunities and the greater their potential share of the direct impact of offshore business. The Newfoundland economy, in view of its relatively small productive capacity, has a limited potential to benefit from offshore development and the Maritime provinces, given their relative proximity, will naturally receive a significant share of the direct impact.

The eastern provinces should be aware of the benefits of exercising some control over the level and rate of development as provided for in the Newfoundland and Labrador Petroleum Regulations.

6.4 Beneficial Impact on the Canadian Economy

The Newfoundland policy of sequencing offshore oil field developments will have a very beneficial impact on the nation as a whole.

Table 6:4:1 compares east coast oil production on the basis of the provincial regulations (for example, a new offshore development beginning every four years) with an uncontrolled pattern of development (a new oil field development beginning in each of three successive years). The sequential approach to oil field development generates a smoother oil production scenario than the almost simultaneous development. Under the simultaneous development, the fields all reach peak production at approximately the same time and production declines thereafter.

It is generally believed that an aggressive development of the tar sand plants and heavy oils in Western Canada may offset the decline in conventional oil production; under these circumstances and without frontier developments, Canada would probably maintain an import requirement of about 150 million barrels per year. Table 6:4:2 contrasts the impact of frontier development on Canadian oil exports and imports under the sequenced versus uncontrolled approach to development.

Table 6:4:1

Estimated Production under the Sequenced and Uncontrolled Development Scenarios (mm bbls. per year)

Year	Sequenced Developments (Provincial Proposal)	Uncontrolled Developments (Federal Proposal)
1985	61.3	61.3
1986	85.4	146.7
1987	104.0	250.7
1988	109.5	298.9
1989	159.9	312.1
1990	169.0	291.7
1991	175.2	253.4
1992	169.7	215.0
1993	211.4	182.9
1994	212.8	155.5
1995	215.4	135.5
1996	206.9	121.2
1997	177.7	105.0
1998	158.4	95.8
1999	139.1	86.3
2000	122.2	83.5

Table 6:4:2

Estimated Exports (+) and Imports (-)
Per Year Under the Sequenced and Uncontrolled
Development Scenarios
(mm bbls. per year)

Year	Sequenced Developments (Provincial Regulations)	Uncontrolled Developments (Federal Proposal)
1984	-150.0	-150.0
1985	- 88.7	- 88.7
1986	- 64.6	- 3.3
1987	- 46.0	+100.7
1988	- 40.5	+148.9
1989	+ 9.9	+162.1
1990	+ 19.9	+141.7
1991	+ 25.2	+103.4
1992	+ 19.7	+ 65.0
1993	+ 61.4	+ 32.9
1994	+ 62.8	+ 5.5
1995	+ 65.4	- 14.5
1996	+ 56.9	- 28.8
1997	+ 27.7	- 45.0
1998	+ 8.4	- 54.2
1999	- 10.9	- 63.7
2000	- 27.8	- 66.5

If the east coast resources are developed in a controlled environment, as would exist under the Newfoundland and Labrador Petroleum Regulations, Canada would be oil self-sufficient by the year 1989 and this self-sufficiency would be maintained until the year 1998. This means that all of Eastern Canada could be supplied with oil from Newfoundland at a strong discount of 10% relative to international prices. Canadian industry could prosper through oil self-sufficiency and a Canadian price for oil that, under the Newfoundland proposal, would be 10% below the international level. This would place the Canadian manufacturing industry at a strong competitive advantage.

In the case of uncontrolled offshore oil development, promoted by the federal government, Canada would become a significant exporter around 1987 but would return to a net import position around 1995. When, and if, the nation develops oil production capacity in excess of our rate of consumption, the excess will either have to be exported in the short run or the rate of production will have to be restrained. If Canada is truly concerned about oil self-sufficiency, it is questionable whether it is a wise policy to pursue an approach to development that generates large scale, perhaps short run, oil surpluses. A controlled rate of oil field development may bring Canada closer to self-sufficiency in oil in both the short run and the long run.

The balance of payments effects of such an uncontrolled development would be unfavorable for the manufacturing and service industries in Canada. If developments of oil are left uncontrolled, the strong exports of oil around 1990 would result in considerable upward pressure on the Canadian dollar. This might seriously affect the competitiveness of many export-oriented manufacturing industries.

It is, therefore, obvious that the Newfoundland policy of sequencing oil field developments is going to be very beneficial to the province, to the Maritimes and to Canada as a whole. The policy will lead to the creation of employment and new industrial development in Newfoundland and the Maritimes, and make Canada self-sufficient in oil at lower then international price levels. A strengthening of the Canadian manufacturing industry and an improvement in Canada's balance of payments position will also result.